Nancy D. Israel
Senior Counsel

April 6, 2021

By E-Filing

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Distributed Energy Resource Planning and Assignment and Recovery of Costs for the Interconnection of Distributed Generation – D.P.U. 20-75

Dear Secretary Marini:

On behalf of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), enclosed for filing in the above matter are National Grid's Responses to Information Requests EDC-1 through EDC-5. Each individual Information Request Response and any attachments is submitted in a separate PDF file. In addition, the entire set of Information Request Responses with associated attachments are submitted as a single PDF file.

Thank you for your attention to this matter. Please contact me if you have any questions regarding this filing.

Sincerely,

Nancy D Israel

Nancy D. Israel, Esq.

Enclosures

cc: Katie Zilgme, Hearing Officer

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Information Request EDC-1

Request:

Identify whether a group or groups of interconnecting customers in the Company's service territory are likely to be presented with interconnection costs in the next 1-1.5 years that are significantly higher than have been historically presented. Include in the Company's response:

a. Detailed information on the group(s), including: geographical region, number of distributed generation ("DG") facilities, capacity in megawatt ("MW"), and estimated timing for conclusion of associated distribution and transmission impact studies;

b. High-level planning estimates of expected interconnection costs for the group(s). Provide data in dollar-amount-per-kilowatt ("$/kW") and by group, where possible;

c. High-level planning estimates of timeline for construction of anticipated EPS upgrades that will be required due to interconnection impacts of the group(s). Provide data by group, where possible;

d. High-level estimates of how much DG capacity will be enabled by the anticipated EPS upgrades for the group(s); and

e. Whether additional DG capacity could be enabled in coordination with anticipated EPS upgrades for the group(s), and if so, high-level estimates of costs and timelines for any additional EPS upgrades required to enable additional DG capacity.

f. Will the anticipated EPS upgrades for the group(s) provide benefits to ratepayers and the Commonwealth beyond enabling renewable energy to interconnect to the EPS?

Response:

With respect to subparagraphs a through d, please see the Attachments to this Response, in addition to the narrative and tables below:

- Attachment EDC-1-1, Supporting workpapers and calculations in the form of a working Microsoft Excel spreadsheet with all cell references and formulae intact
- Attachment EDC-1-2, Group Study Outreach, March 4, 2021
- Attachment EDC-1-3, Central & Western MA Study Update, October 20, 2020
- Attachment EDC-1-4, Central & Western MA ASO Cluster Study Update, March 19, 2020

The groups of interconnecting customers in Group Studies[1] in Central and Western MA identified below are likely to be presented with interconnection costs in the next 1-1.5 years that are significantly higher than have been historically presented, continuing the recent trend of increasing interconnection costs.

a. The following table provides the geographical region of each Group Study in the Central/Western MA area of National Grid's service territory, number of distributed generation ("DG") facilities, capacity in megawatt ("MW") of the facilities applying for interconnection, and estimated timing for conclusion of associated distribution and transmission impact studies:

Group Study Region	Number of DG Facilities	DG Capacity (MW)	Estimated T & D Studies Completion
Ayer-Clinton	3	23	Spring 2022
Barre-Athol	9	41	Spring 2022
Gardner-Winchendon	8	54	Summer 2022
Millbury-Grafton	3	16	Spring 2022
MPL-East*	9	35	Summer 2022

[1] "Group Study" is defined in Section 3.4.1 of the Standards for Interconnection of Distributed Generation, D.P.U. 19-55 and D.P.U. 20-63 EDC Compliance Tariff (Revised 11.12.20) ("Compliance Tariff"). Capitalized terms that are not defined in this Response are defined in the Standards for Interconnection of Distributed Generation, M.D.P.U. No. 1320.

MPL-Northwest	1	5	Spring 2022
Spencer-Rutland	12	62	Spring 2022
Webster-Southbridge-Charlton	12	75	Spring 2022
Shutesbury	5	20	Winter 2021
Total	**62**	**331**	

**MPL stands for Monson-Palmer-Longmeadow.*

Transmission

The preferred distribution infrastructure solutions for a Group Study must be sufficiently developed to identify DG and load injection points to the transmission system. This stage establishes the transmission study start milestone, which will be the point where the distribution system Group Study outputs become inputs to the transmission analysis. New England Power Company ("NEP"), the Company's transmission provider and operator, will initially scope the Affected System Operator ("ASO") studies in a way that may enable parallel studies to be undertaken simultaneously. National Grid anticipates that this approach will help move some DG projects forward for review by the NEPOOL Reliability Committee sooner than otherwise would occur; however, this approach will be subject to the Group Study inputs, the magnitude of MW at each injection point and ISO-NE approval of this ASO study approach. See Attachment EDC-1-2, slide 9. The ASO study timeframe is 6 to 9 months and is accounted for in the above table. See Attachment EDC-1-2, slide 8. Group Study timeframes have been determined in accordance with the Group Study provisions of the Compliance Tariff and are accounted for in the above table. National Grid has advised Group Study members that each Group Study timeframe is 160 Business Days, exclusive of any ASO holds, which will be applied to the Group Studies until the ASO study is completed. See Attachment EDC-1-2, slides 7 and 9.[2] (The Company may exceed the 160 Business Day timeframe if a Group elects the Extended Group Study.)

b. The following table provides high-level planning estimates of expected interconnection costs for each of the Group Studies in dollar-amount-per-kilowatt ("$/kW"):

[2] Group Study members may unanimously consent to proceed with their distribution system impact study in parallel with the ASO study, at their risk. Attachment EDC-1-2, slide 9. (A Group Study is a distribution system impact study, carried out in accordance with the Group Study process, including the Group Study timeframes.)

Group Study Region	Number of DG Facilities	DG Capacity (MW)	Estimated Interconnection Costs	$/kW
Ayer-Clinton	3	23	$ 54,100,000	$ 2,359
Barre-Athol	9	41	$ 116,800,000	$ 2,868
Gardner-Winchendon	8	54	$ 76,800,000	$ 1,412
Millbury-Grafton	3	16	$ 38,300,000	$ 2,359
MPL-East	9	35	$ 81,800,000	$ 2,352
MPL-Northwest	1	5	$ 4,200,000	$ 848
Spencer-Rutland	12	62	$ 284,400,000	$ 4,608
Webster-Southbridge-Charlton	12	75	$ 77,600,000	$ 1,029
Shutesbury	5	20	$ 26,700,000	$ 1,342
Total	**62**	**331**	**$ 760,700,000**	**$ 2,298**

The high-level planning estimates of the interconnection costs for each Group Study region were derived by scaling the estimated costs of distribution system modifications and associated transmission upgrade costs required by previously completed studies in these areas. See Attachment EDC-1-3, slides 7 and 10-11. The above high level estimated interconnection and $/kW costs should not be used to inform project specific financial decisions. These previously completed studies in the area provided the best available basis at this time for deriving the high level planning estimates of the interconnection costs ahead of the more accurate estimates that will be determined by the Company through the course of the Group Studies, which are in the very early stages of engineering. The costs and $/kW values include transmission interconnection costs driven by the previous distribution system impact studies ("DSIS") in these areas but do not include transmission upgrade costs driven by the previous transmission system impact studies ("TSIS") in these areas, which are described below.

Transmission

National Grid conducted several iterations of an ASO study, that is, a TSIS, in Central and Western MA. National Grid advised stakeholders that it had evaluated the interconnection of 391MW in the region, which prompted approximately $50M of transmission system upgrade costs. See Attachment EDC-1-4, slides 6 and 9. Although subsequently there was significant attrition, other applications in the region moved forward, including into the Group Studies. Based on the preliminary review of where the distributed generation in the Group Studies will interconnect to the transmission system, National Grid anticipates that the transmission system upgrades determined to be necessary by the TSIS for the previously proposed the 391MW in this region are a credible indicator of the magnitude of costs associated with the transmission upgrades that will be required for the 331MW in applications currently in the Group Studies. See Attachment EDC-1-3, slide 7. As discussed below in subparagraph e, if the Department determines that additional distribution system capacity should be enabled for future DG, National Grid anticipates that additional engineering solutions would be required for the transmission system.

c. The following table provides a high-level planning estimates of timeline for construction of anticipated EPS upgrades that will be required due to interconnection impacts of the Group Studies:

Region	Number of DG Facilities	DG MW Capacity	Estimated Construction Completion
Ayer-Clinton	3	23	2027 (5 Years)
Barre-Athol	9	41	2027 (5 Years)
Gardner-Winchendon	8	54	2027 (5 Years)
Millbury-Grafton	3	16	2027 (5 Years)
MPL-East	9	35	2027 (5 Years)
MPL-Northwest	1	5	2027 (5 Years)
Spencer-Rutland	12	62	2027 (5 Years)
Webster-Southbridge-Charlton	12	75	2027 (5 Years)
Shutesbury	5	20	2027 (5 Years)

<u>Transmission</u>

As communicated in stakeholder meetings in 2020, any applications seeking to interconnect to the A1/B2 circuits will need to wait until the A1/B2 planned transmission asset condition work has been completed, currently estimated to be 2027, before interconnecting. Relative to the distribution upgrades, the reconductoring of these lines will be the critical path to interconnection in this area. National Grid currently estimates that other transmission upgrades will take approximately 2 to 5 years to complete and may not be critical path activities to the interconnection of the projects in the Group Studies. See Attachment EDC-1-4, slides 9 and 10; Attachment EDC-1-3, slide 7.

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The above table provides high level estimates of construction timelines and does not take into consideration any external factors outside of National Grid's control or other non-EPS limiting factors that could affect those timelines, such as available land suitable for DG development in the area and permitting issues (see D.P.U 20-75 National Grid Comments on Straw Proposal at 50-52), supply chain constraints and customer delays.

d. The following table provides high-level estimates of how much DG capacity will be enabled by the anticipated EPS upgrades for the Group Studies, including the 331MW of DG currently in the Group Studies and excluding any incremental capacity from connected DG in these regions:

Region	**DG MW Enabled Capacity**
Ayer-Clinton	100
Barre-Athol	240
Gardner-Winchendon	165
Millbury-Grafton	50
MPL-East	155
MPL-Northwest	15
Spencer-Rutland	300
Webster-Southbridge-Charlton	180
Shutesbury	30
Total	**1235**

The high level planning estimates of how much DG capacity will be enabled by the anticipated EPS modifications for the Group Studies were derived by scaling the amount of DG capacity that previously completed detailed distribution studies and TSIS identified in these areas. These previously completed studies in the area provided the best available basis at this time for deriving the high level planning estimates of how much capacity will be enabled by the Group Studies, which are in the very early stages of engineering. The values represent substation enabled capacity and do not consider the distribution system feeder level enabled capacity, which is very dependent on the location of the DG that would use this enabled capacity. The distribution system enabled capacity could be greater than or less than these substation-based values but is unable to be quantified without specific DG location analysis. These estimates of enabled DG capacity also do not take into consideration any factors outside of National Grid's control or other non-EPS limiting factors that could affect enablement of additional capacity, such as available land suitable for DG development in the area and permitting issues (see D.P.U. 20-75 National Grid Comments on Straw Proposal at 50-52).

e. With regard to whether additional distribution system feeder level DG capacity could be enabled in coordination with anticipated EPS upgrades for the Group Studies, National Grid is unable to quantify further incremental capacity beyond the values presented in response to subparagraph d above, at this time, because the Group Studies are in the very early stages of engineering.

<u>Transmission</u>

Based on the 1235MW of enabled capacity by the projected upgrades referenced in the table above, National Grid anticipates that the 69Kv loop in Western MA will be converted and operated at 115kV to make sure the transmission system does not become the enabled capacity constraint.

With consideration to anticipated EPS upgrades, four out of the five main circuits in this 69kV loop in Western MA are planned to be rebuilt to a 115kV standard and reconductored over the next five to ten years based on an asset condition need. As a result, the cost of upgrading all of the other associated infrastructure in this area and operating at 115kV is significantly offset by the asset condition replacement projects forecasted by the Company. The total cost forecast for these four EPS circuits is $583M, with two of the EPS circuits planned to come into service in 2027 and the other two in 2031. The 2031 schedule could be re-baselined as necessary, depending on a number of different factors, including coordination and outage planning, which are under evaluation.

69kV Loop Upgrade Need:
As an output of the integrated planning efforts between distribution and transmission system planning at National Grid, as large volumes of distributed generation continue to saturate this area, attempting to interconnect as much as possible to the 115kV system is seen as preferred, as typically there is more margin in what the system can absorb prior to the presentation of adverse impacts. In the continued application of this principle, the distribution enabled capacity was evaluated and produced the following findings.

69kV System:

(A1/B2/E5/F6/D4) Adverse impacts were identified even considering the new upgraded conductor rating assumed by the asset condition projects on the A1/B2/E5/F6, assuming the circuits are operated at 69kV. This is consistent with the findings referenced in Attachment EDC1-4, slides 6-7, where stakeholders were informed of the presentation of significant adverse impacts on the 69kV system where was only 391MW under review.

115kV System:
(A127/B128/I135): Adverse impacts were identified on these circuits, even when some of the circuits have the typical maximum rated conductor used at 115 kV.

345kV System:
(Carpenter Hill): Adverse impacts were even identified where the volume of distributed generation is so large on some circuits, it is triggering overloads on the 345kV system.

When there are problems presenting on the 115kV system and cascading up to the 345kV system, this means that while the 69kV system cannot accommodate this level of DG, neither can the 115kV system in the same area. As a result, the most prudent solution is to enhance the capacity in this area by selecting to convert and the 69kV system to 115kV. This would enable more DG to be interconnected into this system and remove the burden from the current 115kV system. From a transmission standpoint, this is the more technically advantageous and cost-effective long-term solution to enable the large amounts of DG anticipated in this area over the next 10 to 15 years, considering the planned asset condition work in Western MA.

Study Assumptions/Costs:
The screening study completed to conclude the above observations was based on a range of assumptions and may change given more accurate scopes and sufficient time to undertake all of the typical study components, including steady state, stability, short circuit, and PSCAD analysis.

The incremental proposed cost, added to the transmission EPS anticipated project work in the area, is approximately $380M. This is a good faith estimate including all of the circuit and substation work on this 69kV loop, and dynamic devices on the 115kV system. This estimate assumes a range of scopes that would need to be re-evaluated and validated for accuracy if this proposal moves forward.

f. National Grid has considered the state's clean energy and climate change policies during its evaluation of potential customer and Commonwealth benefits. This evaluation considers benefit allocation concepts as compared to the traditional cost causation concept. The Company has explored ideas such as shared capacity across load and generation customers and DG availability as a reliability requirement.

National Grid has considered these potential benefits to customers and the Commonwealth only at a conceptual level and therefore provides the following qualitative benefits that may result from the types of upgrades described in subparagraphs a through d above:

1. Voltage control technology used to mitigate potential DG overvoltage events will be used to prevent load based under voltage events.
2. Reclosers and protective devices remote to the point of interconnection ("POI"), will be used to protect, isolate, and restore a system event regardless of load and generation served.
3. Substation redundancy will be utilized for faster restoration, reducing duration for transformer contingency events.
4. Increasing the Commonwealth's future capability to host new, un-forecasted load growth (e.g., a large warehouse, data center, other C&I customer, electric vehicles, and beneficial heat electrification) in regions that historically have seen low demand and/or low load growth.
5. Other ancillary benefits to the Company's EPS that accompany any new construction (e.g., refreshed tree-trimming clearances, newer poles) that might not otherwise occur until a later planning cycle or when a failure occurs during a storm.

Such shared system uses increase at higher levels within the electric system. Substation equipment will be used in a mutual benefit manner, more so than other distribution assets, and transmission equipment more so than substation assets.

Additionally, the facilities will be vital to creating a resilient system enabling renewable generation to be transmitted and distributed without limitations to regional areas that need the energy. In order to reliably utilize these resources in a matter that will enable the state's clean energy and climate change policies, DG availability will need to be considered and become a fundamental purpose of the electric system. Utilities need to think beyond historical standard interconnection requirement concepts, as these resources will become critical factors in the stability and reliability of the future distribution and transmission electric systems.

In recognition of all these mutual benefits, National Grid believes up to 40% of the DG interconnection costs should be allocated as system benefits to all customers, and recovered through the Reconciling Charge discussed in the Department's Straw Proposal.

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Avg T to D Cost Ratio

28%	72%

Region	Type	Study1 Number of DG Facilities	Study 1 DG Capacity (MW)	Study2 Number of DG Facilities	Study 2 DG Capacity (MW)	Study1 TSIS Costs	Study1 DSIS Costs	Study1 DSIS-T Costs	Study1 DSIS-D Costs	Scale Factor	Scaled TSIS	Scaled DSIS	Total Cost	Scaled DSIS-T	Scaled DSIS-D
Ayer-Clinton	New Study			3	23			$ -	$ -	New Study	9,900,000	54,100,000	$ 64,000,000	$ 15,100,000	$ 39,000,000
Barre-Athol	Previous Study Basis	8	25	9	41	$ 2,119,782	$ 72,452,964	$ 18,326,066	$ 54,126,898	1.61	$ 3,400,000	$ 116,800,000	$ 120,200,000	$ 29,500,000	$ 87,200,000
Gardner	Previous Study Basis	9	21.0	8	54	$ 43,000,000	$ 29,619,328	$ 4,369,968	$ 25,249,360	2.59	$ 111,400,000	$ 76,800,000	$ 188,200,000	$ 11,300,000	$ 65,400,000
Millbury-Grafton	New Study			3	16			$ -	$ -	New Study	$ 7,100,000	$ 38,300,000	$ 45,400,000	$ 10,700,000	$ 27,600,000
MPL-East	Previous Study Basis	8	23.1	9	35	$ 1,949,105	$ 54,256,317	$ 20,188,850	$ 34,067,467	1.51	$ 2,900,000	$ 81,800,000	$ 84,700,000	$ 30,400,000	$ 51,300,000
MPL-Northwest	Previous Study Basis	3	8.1	1	5		$ 6,883,118	$ 434,490	$ 6,448,628	0.61	$ -	$ 4,200,000	$ 4,200,000	$ 300,000	$ 3,900,000
Shutesbury	New Study			5	20		$ -	$ -	$ -	New Study		$ 26,700,000	$ 26,700,000	$ 7,500,000	$ 19,200,000
Spencer-Rutland	Previous Study Basis	8	29.3	12	62		$ 135,230,430	$ 38,312,688	$ 96,917,742	2.10	$ -	$ 284,400,000	$ 284,400,000	$ 80,600,000	$ 203,800,000
Webster-Southbridge-Charlton	Previous Study Basis	2	16.3	12	75		$ 16,754,948	$ 6,334,603	$ 10,420,345	4.63	$ -	$ 77,600,000	$ 77,600,000	$ 29,400,000	$ 48,300,000
Grand Total		38	123.1	62	331	$ 47,068,887	$ 315,197,105	$ 87,966,665	$ 227,230,440		$ 134,700,000	$ 760,700,000	$ 895,400,000	$ 214,800,000	$ 545,700,000

Region	Number of DG Facilities	DG MW In-queue	Estimated Study Completion	Estimated Interconnection Costs w/TSIS	Estimated Interconnection Costs w/o TSIS	$/kW w/TSIS	$/kW w/o TSIS	Estimated Construction Completion	DG MW Enabled	$/kW Enabled w/TSIS	$/kW Enabled w/o TSIS
Ayer-Clinton	3	23	Spring 202	$ 64,000,000	$ 54,100,000	$ 2,790	$ 2,358	2027-5 Years	100	$ 640	$ 541
Barre-Athol	9	41	Spring 202	$ 120,200,000	$ 116,800,000	$ 2,951	$ 2,868	2027-5 Years	240	$ 501	$ 487
Gardner	8	54	Summer 20	$ 188,200,000	$ 76,800,000	$ 3,460	$ 1,412	2027-5 Years	165	$ 1,141	$ 465
Millbury-Grafton	3	16	Spring 202	$ 45,400,000	$ 38,300,000	$ 2,794	$ 2,357	2027-5 Years	50	$ 908	$ 766
MPL-East	9	35	Summer 20	$ 84,700,000	$ 81,800,000	$ 2,435	$ 2,352	2027-5 Years	155	$ 546	$ 528
MPL-Northwest	1	5	Spring 202	$ 4,200,000	$ 4,200,000	$ 848	$ 848	2027-5 Years	15	$ 280	$ 280
Shutesbury	5	20	Winter 202	$ 26,700,000	$ 26,700,000	$ 1,342	$ 1,342	2027-5 Years	30	$ 890	$ 890
Spencer-Rutland	12	62	Spring 202	$ 284,400,000	$ 284,400,000	$ 4,608	$ 4,608	2027-5 Years	300	$ 948	$ 948
Webster-Southbridge-Charlton	12	75	Spring 202	$ 77,600,000	$ 77,600,000	$ 1,029	$ 1,029	2027-5 Years	180	$ 431	$ 431
Total	62	331		$ 895,400,000	$ 760,700,000	$ 2,704	$ 2,298		1235	$ 725	$ 616

40%

TSIS On/Off 0

Test - 40% Multi-Value Allocation

Multi-Value-T	Multi-Value-D	CIP-T	CIP-D	CIP $/kW Enabled	CIP-D $/kW Enabled
$ 6,000,000	$ 15,600,000	$ 9,100,000	$ 23,400,000	$ 325	$ 234
$ 11,800,000	$ 34,900,000	$ 17,700,000	$ 52,300,000	$ 292	$ 218
$ 4,500,000	$ 26,200,000	$ 6,800,000	$ 39,200,000	$ 279	$ 238
$ 4,300,000	$ 11,000,000	$ 6,400,000	$ 16,600,000	$ 460	$ 332
$ 12,200,000	$ 20,500,000	$ 18,200,000	$ 30,800,000	$ 316	$ 199
$ 100,000	$ 1,600,000	$ 200,000	$ 2,300,000	$ 167	$ 153
$ 3,000,000	$ 7,700,000	$ 4,500,000	$ 11,500,000	$ 533	$ 383
$ 32,200,000	$ 81,500,000	$ 48,400,000	$ 122,300,000	$ 569	$ 408
$ 11,800,000	$ 19,300,000	$ 17,600,000	$ 29,000,000	$ 259	$ 161
$ 85,900,000	$ 218,300,000	$ 128,900,000	$ 327,400,000	$ 369	$ 265

5Year CIAC	CIP-D Portion of CIAC	5Year Post CIAC MV-D	5Year Post CIAC CIP-D
$ 7,500,000	$ 5,400,000	$ 15,600,000	$ 18,000,000
$ 11,900,000	$ 8,900,000	$ 34,900,000	$ 43,400,000
$ 15,200,000	$ 13,000,000	$ 26,200,000	$ 26,200,000
$ 7,500,000	$ 5,400,000	$ 11,000,000	$ 11,200,000
$ 11,000,000	$ 6,900,000	$ 20,500,000	$ 23,900,000
$ 800,000	$ 700,000	$ 1,600,000	$ 1,600,000
$ 10,600,000	$ 7,600,000	$ 7,700,000	$ 3,900,000
$ 35,100,000	$ 25,100,000	$ 81,500,000	$ 97,200,000
$ 19,500,000	$ 12,100,000	$ 19,300,000	$ 16,900,000
$ 119,100,000	$ 85,100,000	$ 218,300,000	$ 242,300,000

Group Study Outreach

March 4, 2021

nationalgrid

Disclaimer:

This presentation has been prepared solely as an aid to discussions between Massachusetts Electric Company d/b/a National Grid ("the Company") and interested stakeholders and should not be used for any other purposes. This presentation contains high-level, general information (not project specific) which may not be applicable in all circumstances. The Company makes no guarantees of completeness, accuracy, or usefulness of this information, or warranties of any kind whatsoever, express or implied. The Company assumes no responsibility or liability for any errors or omissions in the content. Nothing contained in this presentation shall constitute legal or business advice or counsel.

No party is authorized to modify this presentation.

It is the customer's responsibility to understand and comply with the requirements of the interconnection tariff, as the same may be revised. The Company notes, for reference only, that there are a number of open interconnection dockets before the Department of Public Utilities at this time.

Terms used but not defined in this presentation shall have the meanings set forth in the interconnection tariff.

Contents page

Safety Moment

Group Study Reference Documents

Group Study Language: [Link to DPU File Room]

- Each Group member is encouraged to review the Group Study provisions to understand the full scope of the process and requirements for the Group Study process.
- The Company will provide visibility and communication in accordance with the Tariff
- Group members responsible to understand individual responsibilities and process tasks that require Group consensus

Common Study Area

"…discrete portion of the Company EPS where [DG] Facilities may have cumulative impacts…"

Group

"…proposed Facilities…in a Common Study Area."

Group Study

"…single study that may be performed at the same time for a Group…"

Common System Modifications

- *"…System Modifications required for more than one Interconnecting Customer's Facility…"*

The summaries in this slide deck are not all inclusive of every tariff required aspects of a Group Study.

Distribution System - *Group Summaries as of 2/25/21*

Group Name	Count of Case Number	Sum of Total MW
Adams-Deerfield 001	4	18.8
Ayer-Clinton 001	3	22.9
Barre-Athol 001	17	63.7
Gardner-Winchendon 001	15	79.9
Millbury-Grafton 001	4	21.2
Monson-Palmer-Longmeadow-East 001	14	54.0
Monson-Palmer-Longmeadow-Northwest 001	9	19.5
Spencer-Rutland 001	16	81.7
Webster-Southbridge-Charlton 001	13	79.5
Grand Total	**95**	**441.2**

Group Study Name	Common Study Area Substations
Adams/Deerfield-001	ADAMS
	BEAR SWAMP UPPER YARD
	BROWN ST
	WALKER ST
	WILLIAMSTOWN
Ayer Clinton-001	AYER
	FITCH RD.
	LAUREL CIRCLE
Barre-Athol-001	BARRE
	CHESTNUT HILL
	ROYALSTON
	SHUTESBURY
	WENDELL DEPOT
Gardner Winchendon-001	CRYSTAL LAKE
	E. WESTMINSTER
	E. WINCHENDON
	WESTMINSTER

Group Study Name	Common Study Area Substations
Millbury-Grafton-001	BLOOMINGDALE
	MILLBURY
	PONDVILLE
	VERNON HILL
Monson-Palmer-Longmeadow-East-001	LITTLE REST RD
	PALMER
	SHEARERS CORNER
	WARE
Monson-Palmer-Longmeadow-Northwest-001	BELCHERTOWN
	FIVE CORNERS
	THORNDIKE
Spencer-Rutland-001	LASHAWAY
	LEICESTER
	MEADOW STREET
	TREASURE VALLEY
Webster Southbridge Charlton-001	E. WEBSTER
	N. OXFORD
	SNOW ST.
	W. CHARLTON

Upcoming Milestones – Distribution Studies

Distribution Group Studies

- Company issued Group Study Agreements on or before 3/1/2021

- Within 15BD of Group Study Agreement issuance, each Group member to:
  1. Sign/execute Group Study agreement
  2. Submit study payment
     - Group Study will not commence until ***full*** payment received from ***all*** members intending to proceed
     - No cure or extension without unanimous Group consent and Company consent

- Group Study timeframe of 160BD

Upcoming Milestones – Affect System Operator

Affected System Operator Milestones

1. CEI to issue a cost estimate to developers for transmission study activities to be completed in parallel with initial stages of the Distribution Group Study
   - Anticipated time frame for payment of transmission study cost approx ***April / May '21***

2. Solicit all of the EMT and Stability models affected developers with payment request
   - Transmission will evaluate and validate all of the models post payment in April 21
   - Continue to engage ISO-NE on potential study approaches & strategies

3. Distribution Group analysis required to determine MW totals at locations of the impacted stations and related upgrades so transmission can appropriately represent in T-study
   - Distribution Group study outputs to Transmission estimated handoff ***June 21***
   - Estimated 6-9 Month Study Duration depending on the outputs of Distribution Group studies and inputs of ISO-NE

Distribution Group & ASO studies must be complete prior to ISA issuance.

Timelines to be updated to Group Members throughout Group Study Process

Study Progression

General

- Any Group member that does not meet the requirements for ASO study will be withdrawn
- Study fees are non-refundable

Parallel Progression

- Distribution SIS (DSIS) and ASO study are two separate and distinct studies
- DSIS will progress to the stage of identifying total MW injection of new DG at area substations
  - Substation currently serving locations today may not be identified to serve those same locations based on distribution solutions
  - Identifying MW injection is required for ASO study to begin
- DSIS will be put on hold until ASO is completed
  - Exception: Unanimous Group consent to progress with DSIS in parallel with ASO
    - *Group members acknowledge risks associated with parallel progression*
    - *DSIS would proceed with distribution solution identified at that time*
    - *Any restudy and/or distribution system modifications required by the Company based on ASO study results will be at the expense of the Group*

Customer Proposed Design Changes

- Any changes require unanimous Group member consent (unless it is an Equipment Exception)
  - Responsibility of the Group member proposing the change to obtain written unanimous consent in form and substance satisfactory to Company
  - Change Request form** created for standardization and ease of administration to help Group members meet tariff requirements
    - **Company reserves all rights to modify the form in its sole discretion
    - Form available here: https://ngus.force.com/servlet/servlet.FileDownload?file=0150W00000FLLIg
  - Change Requests will suspend applicable timelines (for instance, the Group Study would be on hold)
  - Change impact ***alone*** is evaluated relative to impact on area solution/system mods
    - "Mini-study" that occurs while broader Group Study goes on hold
    - Value of results and impact on Group Study timelines is heavily dependent upon the point in the Group Study process where the change is proposed
  - Increases level of decision power for Group members and empowers Group members to direct the course of the Group Study

Note: Change Request are ultimately subject to the Company's consent even where there is unanimous Group consent.

Customer Proposed Design Changes

The following is a high level summary of the requirements for Change Requests under the tariff Section 3.4.1.j

1. Change Request: Group member seeking the change assembles and submits the following:
   a) Unanimous consent (unless it is an Equipment Exception)
   b) Documentation of the project change
2. Change Study identification: Company allowed 20BD to review and provide the following to the Group member seeking the change:
   a) Study requirements to evaluate impact of the specific change
   b) Study cost and/or schedule for that evaluation of specific change*

   *The Company will not study multiple designs for a single project in parallel
3. Group member seeking change allowed 10BD to confirm whether moving forward with Change Study by supplying:
   a) Unanimous consent (unless it is an Equipment Exception)
   b) Full payment of Change Study costs
4. Change Study Request Determination: Company performs Change Study and provides results to Group member seeking the change within 10BD of Change Study completion
5. Group member seeking change to confirm acceptance of Change Study Request Determination within 10BD of receiving determination by providing the following:
   a) If there is member Impact, unanimous consent accepting the Change Study Request Determination
      - If the only member Impact is costs, the Group member requesting the change may elect to pay all increased cost in which case Group member consent is not required
   b) For Equipment Exception Change Requests approved by the Company no unanimous consent is required but the Group member requesting the change is responsible for all increased costs (common and individual).
6. After Change Request process is complete, the Company resumes the step of the interconnection process that was on hold during Change Study

Extension Requests

The following is a high level summary of the requirements for Extension Requests under the tariff Section 3.4.1.k

a) Extension Request: Group member seeking and extension assembles and submits the following:

- Completed Extension Request which must include Group consent and all necessary information and documentation necessary for the Company to consider the request

  Extension Request form created for standardization and ease of administration to help Group members meet tariff requirements *(Company reserves all rights to modify the form in its sole discretion)*

  Form available here:
  https://ngus.force.com/servlet/servlet.FileDownload?file=0150W00000FLLIb

- Company approves or denies request within 20 BD

- If denied solely because of member Impact, the Group member has 10 BDs to provide one of the following:

  - (i) Evidence of Group consent; or
  - (ii) notice that it withdraws its request, in which case the Company will continue processing that Group member's application as-is (provided the Group member is in compliance with such Time Frames).

b) Extension requests will suspend the Company's time frame for the applicable step in the interconnection process for the Group and each individual Group member

Extension Requests

- It is a time frame non-conformance to miss a deadline (including, without limitation, payments due under any applicable Group Study and/or ISA)
  - No Group member shall have a cure or extension period unless the Company and all Group members agree

- Extension Request are ultimately subject to the Company's consent even where there is unanimous Group consent
  - Company considerations include, but are not limited to: tariff provisions, effect on other customers, operational impacts, total duration of request, etc

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Central & Western MA Study Update

October 20, 2020
Online Meeting

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Agenda

00 Welcome/Safety

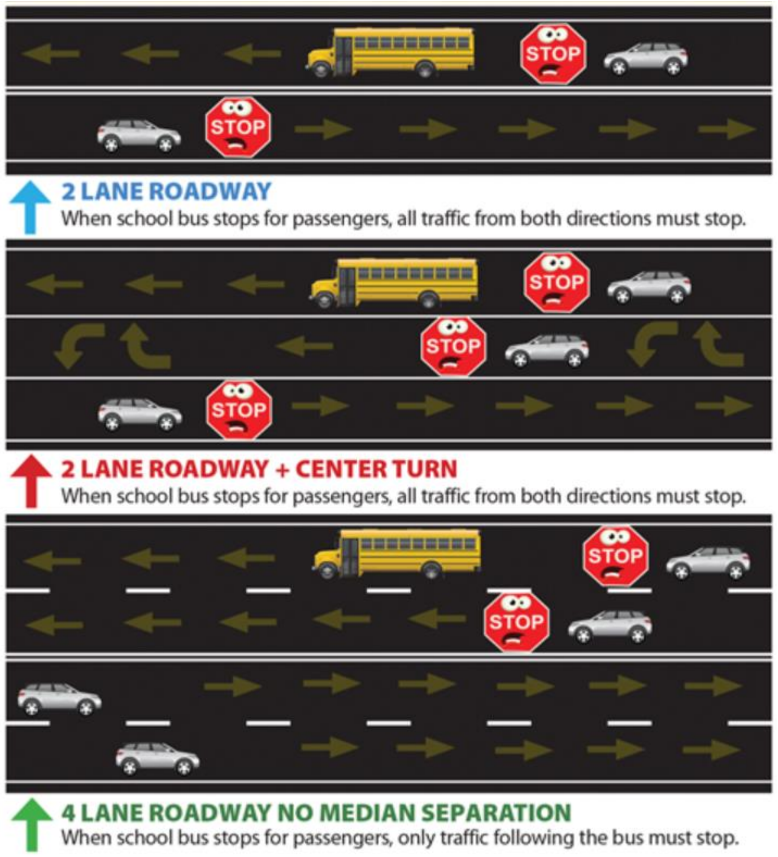
01 Transmission Study Update

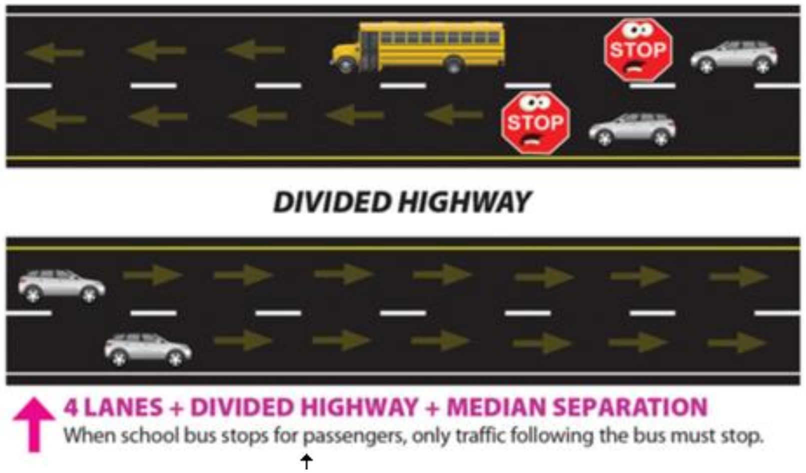
02 Distribution System Impact Study Update

03 Cost Expectations

04 Questions

Safety Message – School Bus Safety





- Slow down! Look for children walking, especially if there are no sidewalks in the neighborhood.
- Yellow flashing lights indicate the bus is preparing to stop to load or unload children. Be prepared to stop your vehicle.
- Red flashing lights and extended stop sign indicate the bus has stopped, and that children are getting on or off. You must wait for the red lights to stop flashing and the extended stop sign is pulled in before you start driving again.

01

Central/Western MA ASO Study
Transmission Study Results

Michael Porcaro, PE
Director, NE DG Ombudsperson

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Transmission Restudy

Original Scope	May-2020	Oct-2020
Total: 937MW	Total: 703MW	Total: 529MW
Part 1: 372MW	Part 1: 312MW	Part 1: 295MW
Part 2: 565MW	Part 2: 391MW	Part 2: 234MW

Focused Restudy with ISO-NE

Results

- All upgrades previously identified requiring developer contribution still required
- Adverse impact solution at the Chestnut Hill 69kV substation no longer required
- Results subject to Reliability Committee approval

Transmission Upgrades Required

No.	Upgrades	Thermal/ Voltage Issue	Company System Improvement Contribution[1]	Developer Contribution[2]	Timeline Required before Interconnection[3]	MW Toward Developer Contribution
1	A-1/B-2 69 kV circuits (All sections): Reconductoring	Thermal	Yes	No	6-7 years	-
2	Deerfield 4 Substation - 69 kV: Buswork and switches	Thermal	Yes	No	4-5 years	-
3	Vernon Substation - 69 kV: Buswork and switches	Thermal	Yes	No	4-5 years	-
4	Otter River Substation - 69kV: Configuration change involving both circuits, and the connection of 32 DVAR of reactive support	Voltage	No	$50M	5-7 years	29.5MW
5	Deerfield 2 Substation - 69kV: Ramp down existing synchronous generation at Deerfield 2 and 3 between contingencies.	Voltage	Not Required	No	N/A	-
6	Wendell Depot – Reactor	Voltage	No	Identified in Distribution Slides		
7	E-5/F-6 Ware Substation - 69kV: O-15N breaker	Thermal	No	$2M	2-3 years	24MW

Notes:
[1] Indicates if a NEP project is planned on this asset
[2] Indicates if there is potential cost to developers
[3] Approximate duration to complete the transmission project

02

Distribution System Impact Study Update

National Grid
Michael Porcaro, PE
Director, NE DG Ombudsperson

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Area Summaries

Most significant geographic areas requiring significant amount of MECo Distribution System Modifications

Scope – Nov 2018

Gardner:	116MW
Leicester:	52MW
Brookfield:	43MW
Barre:	44MW
Athol:	76MW
Palmer:	50MW
Belchertown:	99MW

Total = 480MW

Scope – May 2020

Gardner:	46.7MW, 19 Projects
Leicester:	33.7MW, 9 Projects
Brookfield:	16.2MW, 4 Projects
Barre:	80.2MW, 24 Projects
Athol:	35.1MW, 11 Projects
Palmer:	41.5MW, 13 Projects
Belchertown:	21.8MW, 11 Projects

Total = 275.2MW

Scope – Oct 2020

Gardner:	31.8MW, 9 Projects
Leicester:	21.0MW, 5 Projects
Brookfield:	14.4MW, 3 Projects
Barre:	32.5MW, 10 Projects
Athol:	11.2MW, 4 Projects
Palmer:	13.7MW, 4 Projects
Belchertown	8.8MW; 3 Projects

Total = 133.3MW

System Modification Scope Summaries

Gardner: 31.8MW, 9 Projects

- Upgrade East Winchendon and Westminster Substations

Leicester: 21.0MW, 5 Projects

- Upgrade North Oxford Substation
- Retire existing Leicester Sub and replace with new near Stafford St in Leicester

Brookfield/Meadow St: 14.4MW, 3 Projects

- Upgrade Meadow St and Lashaway Substations

Barre: 32.5MW, 10 Projects

- Upgrade Barre and Ware Substations

Athol: 11.2MW, 4 Projects

- Upgrade Wendell Depot Substation **(required by transmission study)**

Palmer: 13.7MW, 4 Projects

- Upgrade Little Rest Rd Substation

Belchertown 8.8MW; 3 Projects

- Minimal substation upgrades

All areas include extensive distribution line reconfiguration, extension, and/or reconductoring.

Additional transmission upgrades as a result of the transmission study identified on previous transmission study slides

DSIS Shared Asset Cost Summaries

	MW Studied	Substation [1,3,4]	D-Line [1,2,3]	Total [1,3]
Gardner	31.8	$ 9,271,197	$ 17,844,018	$ 27,115,215
Leicester	21.0	$ 31,807,533	$ 25,653,482	$ 57,461,015
Brookfield / Meadow St	14.4	$ 33,385,103	$ 22,526,361	$ 55,911,464
Barre	32.5	$ 41,794,319	$ 45,487,005	$ 87,281,324
Athol	11.2	$ 17,294,559	$ 24,515,859	$ 41,810,418
Palmer	13.7	$ 18,886,171	$ 12,215,065	$ 31,101,236
Belchertown	8.8	$ 482,925	$ 5,515,982	$ 5,998,907

Notes

1. Costs include tax gross up, Transmission PTF Tax Rate:13.30%, Transmission Non-PTF Tax Rate: 12.94%, Distribution Tax Rate 16.47%.
2. D-Line Costs do not include specific Point of Common Coupling estimates.
3. Costs associated with elements of scope that qualify as System Improvement are not the responsibility of the customers, and have been removed from the totals above
4. "Substation" column included NEP and MECo scope associated with substation upgrades

03

Cost Expectations

National Grid
Michael Porcaro, PE
Director, NE DG Ombudsperson

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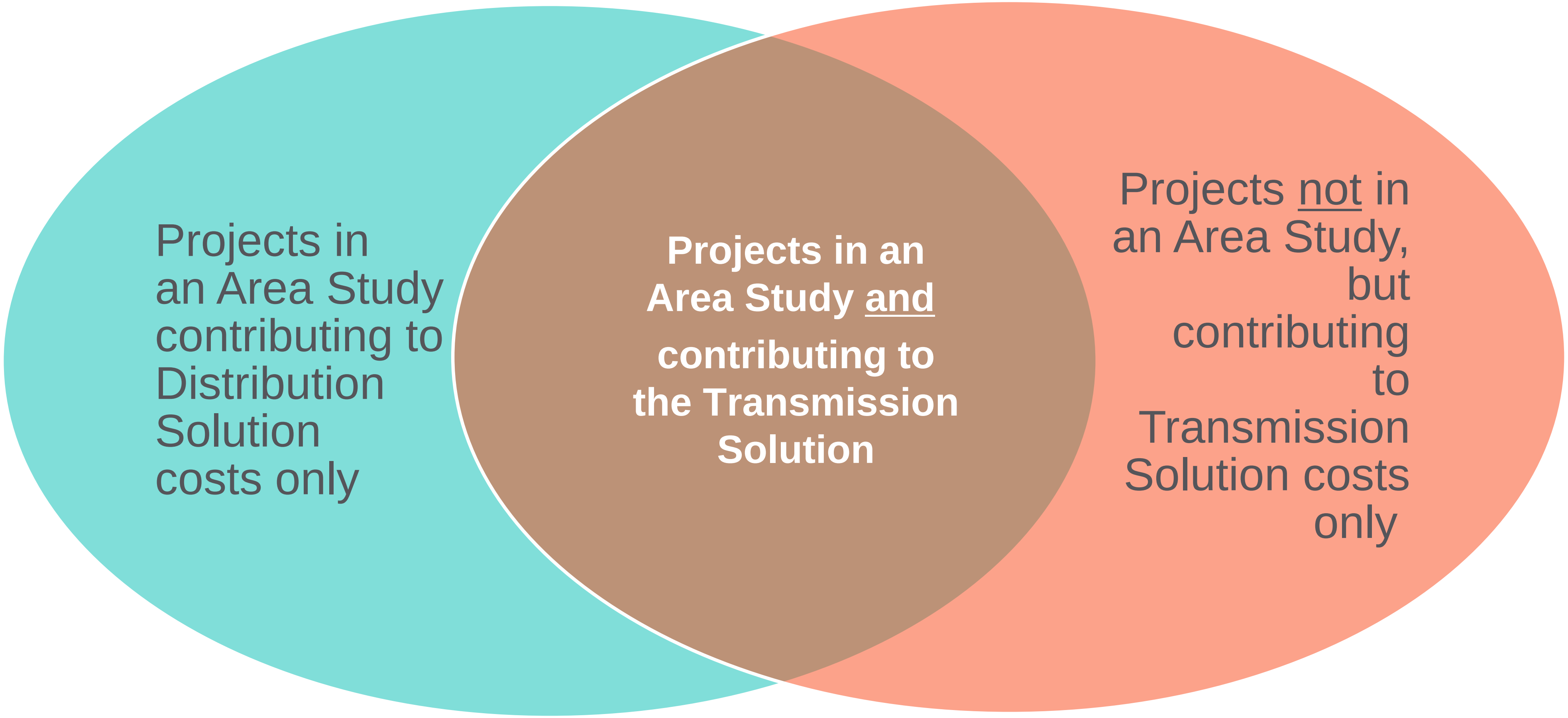
Cost Estimate Expectations



Note: Sizing of diagram is not proportional to MW or project totals. Visual provided here as a reference only for concept of project overlap potential

Cost Estimate Expectations

Upgrade costs identified from both the transmission and distribution studies have removed System Improvement costs

- Although costs are removed, work will be required to complete prior to interconnection

Estimated costs for distribution System Modifications from the distribution Detailed Studies are +/-10%

- In accordance with MA interconnection tariff MDPU 1320

Estimated costs for ASO transmission system upgrades will be reconciled to actual costs

- In accordance with NEP's FERC tariff

Cost Sharing

- Distribution System Modifications will be cost shared on per MW basis
- Transmission upgrades will be shared on per MW basis
- ISAs will identify total area costs, as well as pro-rata share
- Total area costs will not change, however pro-rata allocation may change based on attrition

Carrying Charges

- ASO Annual On-going Carrying Charges
  - These on-going charges include O&M, property taxes, and other carrying costs
  - Carrying charge rate is calculated annually in accordance with FERC approved tariffs
- NEP's 2020 rate is 5.21%
- Calculated based on formula identified in NEP's Schedule 21 ("Direct Assignment Facility (DAF)" section) and data from the FERC Form 1
  - The total charge is calculated as the product of the total reconciled transmission upgrade costs made by the ASO and the annual carrying charge rate

All ASO upgrade costs as well as the associated on-going carrying charges will be passed through to those DG projects causing the need for ASO upgrades

Interconnection Service Agreements

Delivery upon receipt of customer document corrections

ISA includes:

- *Distribution system modifications*
    - Project specific cost (site specific costs and pro-rata share of shared scope)
    - Implementation schedule
- *Transmission upgrades (if applicable)*
    - Project specific cost
    - Implementation schedule
- "Cost Allocation" based on area costs (if applicable) and reassessments for attrition. The current method is based on Cost Causation principle.
- ASO Upgrade cost and associated on-going carrying charges (if applicable)
    - Carrying charges will be collected when the DG facility is energized plus cost security before that estimated date
- Contingencies for permitting, approvals and land rights

Payment schedule in accordance with MDPU 1320 (amended by recent queue mgmt. order)

- 25% in 60BD, remaining 75% in subsequent 120BD

Next Steps

Customer decision

- Correct documents as applicable, and execute ISA to proceed toward design and construction activities
- Withdraw application

Asset condition planned system improvement work to the transmission system will progress regardless of customer decisions

New distribution study groups are in formation for these areas, aligned with the Group Study provision of the DG tariff

- DPU orders relevant to Group Study here

QUESTIONS?

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Central & Western MA ASO Cluster Study Update

March 19, 2020
WebEx Attendance

nationalgrid

Agenda

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- Welcome/Safety
- Affected System Operator (ASO) Study Update
  - Study Status
  - Steady State Results
  - Next Steps

- Distribution System Impact Study Update
  - Timeline
  - Deliver Distribution Impact Study (DSIS)
  - Distribution Modification Costs & Schedule
  - Collect Detailed Agreement w/Study Fees
  - Estimated Detailed Distribution Costs
  - Reconcile Distribution Study Costs
  - Conduct Detailed Study
  - Impact of Attrition
  - Deliver Interconnection Service Agreements (ISAs)
  - Projects not in an "Area Distribution Study"
  - "Early" ISAs (upon request)
  - Project Progression

Safety Message

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Operating BAU and there are no delays to this study

No delays to applications to being processes

Monitoring the fluid situation closely

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01

Central/Western MA ASO Study
Affected System Operator Study Update

Barry Ahern – Transmission Planning, NEP

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Part 2 – Scope Review (Dec 5th)

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Scope – May 2019
- Total: 937MW
- Part 1: 372MW
- Part 2: 565MW

Scope – November 2019
- Total: 751MW
- Part 1: 325MW
- Part 2: 431MW

Scope – February 2020
- Total: 703MW
- Part 1: 312MW
- Part 2: 391MW

Status:

1. Steady State	Complete (90%)
2. Stability	Ongoing (40%)
3. Short Circuit	Ongoing (50%)
4. PSCAD	Ongoing (40%)

Note: Study components 2-4 rely on Steady State conclusions

Steady State - Adverse Impacts

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Thermal Overloads

Line

*A-1/B-2 69 kV circuits (All sections)

E-5/F-6 69kV circuits (sections)

Substation

Deerfield 4 - 69 kV buswork and Switches.

Vernon - 69 kV buswork and Switches.

Chestnut Hill - 69 kV buswork and Switches.

Voltages

Substation

Substations off A-1/B-2

Deerfield 2 69kV

***Significant overloads observed under a number of different scenarios on all cases studied**

Steady State – Affected Applications

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Thermal Overloads

Line

A-1/B-2 69 kV circuits (All sections)

E-5/F-6 69kV circuits (sections)

Substation

Deerfield 4 - 69 kV buswork and Switches.

Vernon - 69 kV buswork and Switches.

Chestnut Hill - 69 kV buswork and Switches.

Voltages

Substation

Substations off A-1/B-2

Deerfield 2 69kV

A-1/B-2 Blue: 50MW

Applications that cannot connect until T upgrades are completed

E-5/F-6 Orange: 29MW

Applications that cannot connect until T upgrades are completed

Interconnection Timeframe not Affected: 312MW

Provisionally, 312MW can connect before T-upgrades are made

Steady State Adverse Impacts: A-1/B-2, 50MW

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Thermal Overloads	Company System Improvement Contribution[1]	Developer Contribution[2]	Timeline Required before Interconnection[3,4]
A-1/B-2 69 kV circuits (All sections): *Reconductoring*	Yes	$10-15M	5-7 years
Deerfield 4 Substation - 69 kV: *Buswork and switches*	Yes	No	4-5 years
Vernon Substation - 69 kV: *Buswork and switches*	Yes	No	4-5 years
Chestnut Hill Substation - 69 kV: *Buswork and switches*	Yes	No	5-7 years
Voltage Issues			
Otter River Substation - 69kV: *Configuration change involving both circuits, and the connection of 32 DVAR of reactive support*	No	$50-60M	5-7 years
Deerfield 2 Substation - 69kV: *Ramp down existing synchronous generation at Deerfield 2 and 3 between contingencies.*	Not Required	No	N/A

Notes:
[1] Indicates if a NEP project is planned on this asset (A-1/B-2 reconductoring project is in progress)
[2] Indicates if there is potential cost to developers (A-1/B-2 reconductoring scope would be an incremental cost to the in-progress project)
[3] Approximate duration to complete the transmission project (Assessing opportunities to expedite schedules)
[4] A-1/B-2 reconductoring is critical path to allow all 50MW to interconnect

Steady State Adverse Impacts: E-5/F-6, 29MW

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Thermal Overloads	Company System Improvement Contribution[1]	Developer Contribution[2]	Timeline Required before Interconnection[3]
E-5/F-6 Ware Substation - 69kV: *O-15N breaker*	No	$1-5M	2-3 years
Voltage Issues			
None identified	N/A	N/A	N/A

Notes:
[1] Indicates if a NEP project is planned on this asset
[2] Indicates if there is potential cost to developers
[3] Approximate duration to complete the transmission project

Transmission Next Steps

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Feb 2020 Identify the final transmission upgrades required for thermal/voltage

Engineering/Permitting/Siting activities in progress on relevant asset projects

Mar 2020 Conduct stakeholder meeting

Complete & Conclude (with identified upgrades)

PSCAD

Stability

Short Circuit

April 2020 Complete stakeholder requested sensitivity analysis on all study components

Submit all of the PPAs to ISO for review

Determine cost allocation for upgrades

May 2020 Final Presentation to Reliability Committee

Expected stakeholder follow up as needed

02

Distribution System Impact Study Update

National Grid
Will Kern – Customer Energy Integration
Mike Porcaro – Distribution Planning, MECo

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Gantt Chart

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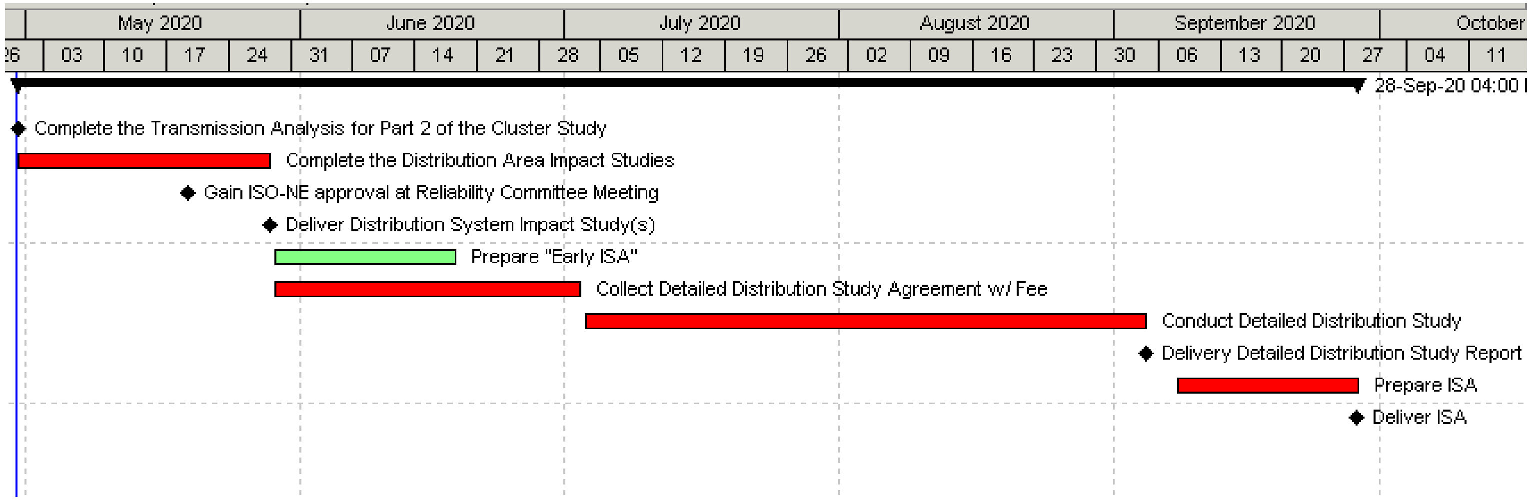

Milestone dates

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Task	Duration (Business Days)	Target Date
Distribution System Impact Study	20	5/28/2020
"Early" ISA	15	upon request
Detailed Study Agreement w/ Payment	15	6/19/2020
Distribution Detailed Study	45*	7/3/2020
ISA Delivery	15	9/28/2020

*from receipt of full payment

Deliver Distribution System Impact Study
(for projects in an Area Study)

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- Impact Studies would be prepared at an "Area Study" level.
- Impact Studies would include:
  - Scope of distribution system modifications required for the Area
  - Total estimated for area distribution system modifications
    - Will not include any site-specific costs
- Impact Studies would not include site specific information that will be in the ISA, such as:
  - A construction schedule
  - Project or site-specific costs or operating conditions
- "Early" ISA would be available upon request

Distribution Estimated Modification Cost & Schedule

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- Barre Area
  - Approximately $80M; 4 years
  - Total of 23 applications comprising approx 80MW
- Belchertown Area
  - Approximately $19M; 3.5 years
  - Total of 5 applications comprising approx 18MW
- Athol Area
  - Approximately $46M; 4.5 years
  - Total of 11 applications comprising approx 36MW
- Gardner Area
  - Approximately $94M; 4.5 years
  - Total of 14 applications comprising approx 50MW
- Leicester Area
  - Approximately $64M; 5 years
  - Total of 9 applications comprising approx 34.5MW
- Brookfield Area
  - Approximately $40M; 4.5 years
  - Total of 4 applications comprising approx 16MW
- Palmer Area
  - Approximately $55M; 4.5 years
  - Total of 11 applications comprising approx 42MW

Cost estimates are reflective of overall distribution area scope

Elements of scope in some areas may be qualified as System Improvement, which could reduce customer contribution

*these costs and schedule assume no attrition

Collect Detailed Study Agreement w/ Study Fees

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- Detailed Study fees will be determined on a per MW basis, which will be subject to increase for projects with area solutions if there is project attrition
- 15 business days will be allotted for payment
  - Projects will receive a default warning if not signed with payment paid within 15BD
  - 10 BD cure periods will be applied in accordance with tariff
  - Detailed Study fee will be non-refundable
- Failure to meet timeline to sign and make payment will result in project being withdrawn
- Detailed Study fees collected will be used to reimburse MECo for some work already performed in good faith to progress projects in parallel with transmission study and to complete the remaining Detailed Study work

Estimated Detailed Distribution Study Fees

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- Gardner Area
  - Detailed Distribution Study – $265k
  - Expected cost per MW - $10,600
- Leicester Area
  - Detailed Distribution Study – $209k
  - Expected cost per MW - $12,100
- Brookfield Area
  - Detailed Distribution Study – $132K
  - Expected cost per MW - $16,500
- Barre Area
  - Detailed Distribution Study – $95k
  - Expected cost per MW - $2,400
- Belchertown Area
  - Detailed Distribution Study – $62k
  - Expected cost per MW - $6,900
- Athol Area
  - Detailed Distribution Study – $69k
  - Expected cost per MW - $3,900
- Palmer Area
  - Detailed Distribution Study – $51k
  - Expected cost per MW - $2,500

*these costs assume 50% attrition - $$ are approximated

Reconcile Distribution Study Costs

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- Detailed Study fee will be allocated based on prorated MW basis and will be initially calculated assuming 50% attrition rate as a worst-case scenario.
- These costs will be allocated among all of the projects in that area.
- Detailed Study fees are non-refundable except to the extent actual costs are less than estimated costs (see last bullet).
- The Company has incurred DSIS costs of >$180K for work already performed in good faith to progress projects in parallel with the ASO study.
    - A portion of the Detailed Study fees collected will be used to reimburse MECo for such previously incurred DSIS cost
- The Detailed Studies will be reconciled at the end of the study and any unused funds will be returned.

Conduct Detailed Study

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- Expected to take 45 business days to complete
  - Delivery date may be impacted by significant attrition
- Incorporate Transmission study results
- Assess effects of attrition
- Refine scope and cost and deliver estimates at a project specific level provided, for projects that are part of an area solution, total costs will still need to be accounted for in manner of allocation
- Results will be delivered as they become ready

Impact of Attrition

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- Attrition is expected due to significant scope and high cost of Distribution modifications along with extended timelines for both Distribution and Transmission modifications
- Significant attrition would impact:
  - Transmission Cluster Study results
  - Distribution Detailed Study timelines
  - per MW Detailed Study fees
  - Scope of the Distribution and/or Transmission modifications
  - Delivery timeline for the ISA or "Early" ISA Amendment

Deliver Interconnection Service Agreements (ISAs)

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- Will be delivered 15 business days after completion/delivery of Detailed Study
- Will include:
  - Distribution area modifications
    - Project specific cost
    - Implementation schedule
  - Transmission modifications (if applicable)
    - Project specific cost
    - Implementation schedule
  - "Cost Allocation" based on area costs (if applicable) and reassessments for attrition. The current method is based on Cost Causation principle. The Company filed comments in the open DPU 19-55 DG interconnection tariff docket that propose potential refinements to the Cost Causation principle.
  - Contingencies for permitting, approvals and land rights

Projects not in a Distribution Area Study

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- These projects will move forward under their own individual timeframes
  - 26 projects
  - 112MW
  - 10 substations
    - Walker St, Bear Swamp, E. Webster, Litchfield, Millbury, Shutesbury, Fiskdale, Snow St, Treasure Valley, W. Charlton
- Will be regulated by the Tariff process and timelines
- These projects may or may not require a Detailed Study
- Will be subject to Transmission modification costs and timelines (if applicable)

"Early" ISAs

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- Will be delivered within 15BD after formal request from the interconnecting customer
  - Request to be made in the National Grid DG Portal
- Will be based on the Distribution System Impact Study
  - High level area distribution system modifications scope and cost
- Will be subject to the payment timelines outlined in the Tariff for 25% and 75% payments
- "Early" ISA will be amended once Detailed Study is complete
  - Payment timelines will be maintained

Project Progression

- Customer confirmation & commitment
  - Minimize speculative projects
  - Payments toward Detailed Studies
  - Timely ISA execution & payment
- Prior to September
  - Coordinating with internal project management and construction teams
  - Securing contractors to engineer, procure, construct activities
- Regulatory discussions occurring on permitting complexities
- Exploring construction phasing opportunities to expedite
- Progressing work in parallel to greatest extent possible

03

QUESTIONS?

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Information Request EDC-2

Request:

If the estimates of expected interconnection costs identified in response to EDC-1 were allocated pursuant to the cost assignment and recovery provisions of the Department's straw proposal, provide high-level estimates of bill impacts for ratepayers if the costs were amortized for Recovery over 10, 20, and 30 years.

Response:

The high-level illustrative monthly bill impacts for a 500 kWh residential customer receiving Basic Service are summarized on page 1 of Attachment EDC-2-1. The Company has presented illustrative bill impacts associated with the first five years of revenue requirements associated with each of the assumed amortization periods of 10, 20, and 30 years. Pages 2 through 4 calculate the illustrative monthly bill impact at each assumed annual amortization period for the capital costs identified in Information Request EDC-1. The Company began the bill impact analysis using a monthly residential bill based on rates currently in effect and determined each year's incremental increase in the illustrative factor to arrive at the illustrative incremental bill impact for each successive year.

Attachment EDC-2-2 presents the summary of the first five years of illustrative annual revenue requirements under the three annual amortization periods upon which the bill impacts are based. Attachments EDC-2-3 through EDC-2-5 present the calculation of the illustrative revenue requirements at each assumed annual amortization period for the capital costs identified in Information Request EDC-1.

The illustrative bill impacts and illustrative revenue requirements presented in this response reflect those resulting from the Company's investment in distribution plant additions and cost of removal and exclude investments in transmission plant that may be required by the Company or its transmission affiliate, New England Power Company. In addition to the issues identified in the Company's response to Information Request EDC-5, the Company does not have a complete estimate of all associated transmission upgrades and how they would be allocated between DG customers and distribution customers, upon which to then allocate consistent with the allocation of transmission costs billed to the Company (on the basis of the Company's coincident peak allocator).

Prepared by or under the supervision of: Ian Springsteel and Stephanie Briggs

Massachusetts Electric Company
Nantucket Electric Company
Summary of Illustrative Bill Impacts
10, 20, and 30 Year Amortization

		Year 1	Year 2	Year 3	Year 4	Year 5
		(a)	(b)	(c)	(d)	(e)
(1)	Illustrative % Increase @ 10 Year Amortization	1.24%	0.23%	-0.11%	-0.18%	-0.18%
(2)	Illustrative % Increase @ 20 Year Amortization	1.06%	0.11%	-0.03%	-0.12%	-0.11%
(3)	Illustrative % Increase @ 30 Year Amortization	1.00%	0.06%	-0.01%	-0.10%	-0.09%

(1) Page 2, Line (11)
(2) Page 3, Line (11)
(3) Page 4, Line (11)

Massachusetts Electric Company
Nantucket Electric Company
Calculation of Illustrative Factor and Residential Bill Impact
Assuming 10 Year Amortization

		Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
		(a)	(b)	(c)	(d)	(e)
(1)	Total Annual Recovery	$48,518,984	$57,717,406	$53,476,737	$46,187,833	$39,331,788
(2)	Residential Distribution Revenue Allocator	57.7%	57.7%	57.7%	57.7%	57.7%
(3)	Total Allocated Residential Recovery	$27,995,454	$33,302,943	$30,856,077	$26,650,379	$22,694,442
(4)	Forecasted Annual Residential kWh	8,111,041,508	8,111,041,508	8,111,041,508	8,111,041,508	8,111,041,508
(5)	Illustrative Annual Factor	$0.00345	$0.00410	$0.00380	$0.00328	$0.00279
(6)	Illustrative Incremental Change in Factor	$0.00345	$0.00065	($0.00030)	($0.00052)	($0.00049)
(7)	Monthly Residential kWh Deliveries	500	500	500	500	500
(8)	Year-Over-Year Illustrative Increase in Monthly Bill	$1.73	$0.33	($0.15)	($0.26)	($0.25)
(9)	Residential Monthly Bill at Start of Year	$139.56	$141.29	$141.62	$141.47	$141.21
(10)	Illustrative Residential Monthly Bill	$141.29	$141.62	$141.47	$141.21	$140.96
(11)	Illustrative % Increase	1.24%	0.23%	-0.11%	-0.18%	-0.18%

(1) Attachment EDC-2-2, Line 4
(2) Currently effective R-1/R-1 Distribution Revenue Allocator percentage
(3) Line (1) x Line (2)
(4) Company forecast for for the furthest year in the Company's forecast (calendar year 2025)
(5) Line (3) ÷ Line (4), trucated to 5 decimal places
(6) Line (5) - Line (5) from prior year
(7) 500 kWh
(8) Line (6) x Line (7)
(9) Year 1: Page 5; all other years: prior year Line 16
(10) Line (8) + Line (9)
(11) Line (8) ÷ Line (9)

Massachusetts Electric Company
Nantucket Electric Company
Calculation of Illustrative Factor and Residential Bill Impact
Assuming 20 Year Amortization

		Year 1	Year 2	Year 3	Year 4	Year 5
		(a)	(b)	(c)	(d)	(e)
(1)	Total Annual Recovery	$41,506,957	$45,648,574	$44,474,730	$39,885,384	$35,447,946
(2)	Residential Distribution Revenue Allocator	57.7%	57.7%	57.7%	57.7%	57.7%
(3)	Total Allocated Residential Recovery	$23,949,514	$26,339,227	$25,661,919	$23,013,867	$20,453,465
(4)	Forecasted Annual Residential kWh	8,111,041,508	8,111,041,508	8,111,041,508	8,111,041,508	8,111,041,508
(5)	Illustrative Annual Factor	$0.00295	$0.00324	$0.00316	$0.00283	$0.00252
(6)	Illustrative Incremental Change in Factor	$0.00295	$0.00029	($0.00008)	($0.00033)	($0.00031)
(7)	Monthly Residential kWh Deliveries	500	500	500	500	500
(8)	Year-Over-Year Illustrative Increase in Monthly Bill	$1.48	$0.15	($0.04)	($0.17)	($0.16)
(9)	Residential Monthly Bill at Start of Year	$139.56	$141.04	$141.19	$141.15	$140.98
(10)	Illustrative Residential Monthly Bill	$141.04	$141.19	$141.15	$140.98	$140.82
(11)	Illustrative % Increase	1.06%	0.11%	-0.03%	-0.12%	-0.11%

(1) Attachment EDC-2-2, Line 8
(2) Currently effective R-1/R-1 Distribution Revenue Allocator percentage
(3) Line (1) x Line (2)
(4) Company forecast for for the furthest year in the Company's forecast (calendar year 2025)
(5) Line (3) ÷ Line (4), trucated to 5 decimal places
(6) Line (5) - Line (5) from prior year
(7) 500 kWh
(8) Line (6) x Line (7)
(9) Year 1: Page 5; all other years: prior year Line 16
(10) Line (8) + Line (9)
(11) Line (8) ÷ Line (9)

Massachusetts Electric Company
Nantucket Electric Company
Calculation of Illustrative Factor and Residential Bill Impact
Assuming 30 Year Amortization

		Year 1	Year 2	Year 3	Year 4	Year 5
		(a)	(b)	(c)	(d)	(e)
(1)	Total Annual Recovery	$39,088,435	$41,323,237	$40,931,324	$37,072,120	$33,325,934
(2)	Residential Distribution Revenue Allocator	57.7%	57.7%	57.7%	57.7%	57.7%
(3)	Total Allocated Residential Recovery	$22,554,027	$23,843,508	$23,617,374	$21,390,613	$19,229,064
(4)	Forecasted Annual Residential kWh	8,111,041,508	8,111,041,508	8,111,041,508	8,111,041,508	8,111,041,508
(5)	Illustrative Annual Factor	$0.00278	$0.00293	$0.00291	$0.00263	$0.00237
(6)	Illustrative Incremental Change in Factor	$0.00278	$0.00015	($0.00002)	($0.00028)	($0.00026)
(7)	Monthly Residential kWh Deliveries	500	500	500	500	500
(8)	Year-Over-Year Illustrative Increase in Monthly Bill	$1.39	$0.08	($0.01)	($0.14)	($0.13)
(9)	Residential Monthly Bill at Start of Year	$139.56	$140.95	$141.03	$141.02	$140.88
(10)	Illustrative Residential Monthly Bill	$140.95	$141.03	$141.02	$140.88	$140.75
(11)	Illustrative % Increase	1.00%	0.06%	-0.01%	-0.10%	-0.09%

(1) Attachment EDC-2-2, Line 12
(2) Currently effective R-1/R-1 Distribution Revenue Allocator percentage
(3) Line (1) x Line (2)
(4) Company forecast for for the furthest year in the Company's forecast (calendar year 2025)
(5) Line (3) ÷ Line (4), trucated to 5 decimal places
(6) Line (5) - Line (5) from prior year
(7) 500 kWh
(8) Line (6) x Line (7)
(9) Year 1: Page 5; all other years: prior year Line 16
(10) Line (8) + Line (9)
(11) Line (8) ÷ Line (9)

Massachusetts Electric Company
Nantucket Electric Company
Calculation of Current Monthly Residential Bill

		Effective March 1, 2021	Amount
(1)	500	(a)	(b)
	Delivery Service		
(2)	Customer Charge		$7.00
(3)	Base Distribution Charge	$0.04906	
(4)	CapEx Factor	$0.00352	
(5)	Basic Service Adjustment Factor	$0.00105	
(6)	Residential Assistance Adjustment Factor	$0.00488	
(7)	Storm Fund Replenishment Factor	$0.00301	
(8)	Pension/PBOP Factor	$0.00179	
(9)	Revenue Decoupling Mechanism Adjustment Factor	$0.00255	
(10)	Attorney General Consulting Expense Factor	$0.00003	
(11)	Solar Cost Adjustment Factor	$0.00033	
(12)	Smart Grid Distribution Adjustment Factor	$0.00008	
(13)	Net Metering Recovery Surcharge	$0.01163	
(14)	Renewable Energy Recovery Factor	$0.00075	
(15)	Tax Act Credit Factor	($0.00062)	
(16)	Vegetation Management Factor	$0.00054	
(17)	Grid Modernization Factor	$0.00032	
(18)	Total Distribution Energy Charge	$0.07892	$39.46
(19)	SMART Factor	$0.00315	$1.58
(20)	Electric Vehicle Program Factor	$0.00011	$0.06
(21)	Transition Charge	($0.00104)	($0.52)
(22)	Transmission Service Adjustment Factor	$0.03858	$19.29
(23)	Energy Efficiency Charge	$0.02098	$10.49
(24)	Renewables Charge	$0.00050	$0.25
(25)	Subtotal Delivery Charges		$77.61
	Supply Service		
(26)	Base Basic Service Charge	$0.11965	$59.83
(27)	Basic Service Admin Cost Factor	$0.00011	$0.06
(28)	Smart Grid Customer Cost Adjustment Factor	$0.00412	$2.06
(29)	Commodity Subtotal	$0.12388	$61.95
(30)	Total		$139.56

(a) M.D.P.U. No. 1-21-C
(b) Line (1) x Column (a), Lines (18) thru (28)

Massachusetts Electric Company
Distribution DG Capital
Illustrative Revenue Requirement - 10 Years

			Year 1	Year 2	Year 3	Year 4	Year 5
			(a)	(b)	(c)	(d)	(e)
	10 Year Amortization						
1	Annual Revenue Requirement on CapEx	Attachment EDC-2-3, Page 1, Line 5	$29,419,484	$57,717,406	$53,476,737	$46,187,833	$39,331,788
2	O&M related to capex	Attachment EDC-2-3, Page 1, Line 7	$19,099,500	$0	$0	$0	$0
3							
4	Total Revenue Requirement		$48,518,984	$57,717,406	$53,476,737	$46,187,833	$39,331,788
	20 Year Amortization						
5	Annual Revenue Requirement on CapEx	Attachment EDC-2-4, Page 1, Line 5	$22,407,457	$45,648,574	$44,474,730	$39,885,384	$35,447,946
6	O&M related to capex	Attachment EDC-2-4, Page 1, Line 7	$19,099,500	$0	$0	$0	$0
7							
8	Total Revenue Requirement		$41,506,957	$45,648,574	$44,474,730	$39,885,384	$35,447,946
	30 Year Amortization						
9	Annual Revenue Requirement on CapEx	Attachment EDC-2-5, Page 1, Line 5	$19,988,935	$41,323,237	$40,931,324	$37,072,120	$33,325,934
10	O&M related to capex	Attachment EDC-2-5, Page 1, Line 7	$19,099,500	$0	$0	$0	$0
11							
12	Total Revenue Requirement		$39,088,435	$41,323,237	$40,931,324	$37,072,120	$33,325,934

Massachusetts Electric Company
Distribution DG Capital
Summary Illustrative Revenue Requirement - 10 Years

			Year 1	Year 2	Year 3	Year 4	Year 5
			(a)	(b)	(c)	(d)	(e)
1	Cumulative Net Historic Capital Adjustment						
2	Annual Revenue Requirement on CapEx	Page 2, Line (32)	$29,419,484	$57,717,406	$53,476,737	$46,187,833	$39,331,788
3							
4	Cumulative Net CapEx Adjustment		$29,419,484	$57,717,406	$53,476,737	$46,187,833	$39,331,788
5							
6	O&M related to capex		$19,099,500	$0	$0	$0	$0
7							
8	Total		$48,518,984	$57,717,406	$53,476,737	$46,187,833	$39,331,788

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Illustrative Revenue Requirement - 10 Years

	Year		1 (a)	2 (b)	3 (c)	4 (d)	5 (e)
	Depreciable Plant Additions						
(1)	Distribution Plant Additions		$496,587,000	$0	$0	$0	$0
(2)	CIAC/CIP		($195,998,000)	$ (19,218,000)	$ (19,740,000)	$ (20,261,000)	$ (19,789,000)
(3)	Accum. Gross Distribution Plant Additions	PY Line (3) + CY Line (1) & (2)	$300,589,000	$281,371,000	$261,631,000	$241,370,000	$221,581,000
(4)	Cumulative Cost of Removal		$30,013,500	$30,013,500	$30,013,500	$30,013,500	$30,013,500
	Deferred Tax Calculation:						
(5)	Composite Book Depreciation Rate	Assumes 10 year	10.00%	10.00%	10.00%	10.00%	10.00%
	Vintage Year Tax Depreciation:						
(6)	Federal Tax Depreciation	Page 3, Line (31)	$60,072,400	$54,106,020	$43,284,816	$34,627,853	$27,714,306
(7)	Cumulative Federal Tax Depreciation	PY Line (7) + CY Line (6)	$60,072,400	$114,178,420	$157,463,236	$192,091,089	$219,805,395
(8)	State Tax Depreciation	Page 3, Line (46)	$60,072,400	$54,106,020	$43,284,816	$34,627,853	$27,714,306
(9)	Cumulative State Tax Depreciation	PY Line (9) + CY Line (8)	$60,072,400	$114,178,420	$157,463,236	$192,091,089	$219,805,395
(10)	Book Depreciation	Year 1: Line (3) x Line (5) x 50%; Year 2 and beyond: Line (3) x Line (5)	$15,029,450	$28,137,100	$26,163,100	$24,137,000	$22,158,100
(11)	Cumulative Book Depreciation	PY Line (11) + CY Line (10)	$15,029,450	$43,166,550	$69,329,650	$93,466,650	$115,624,750
(12)	Cumulative State Book / Tax Timer	Line (9) - Line (11)	$45,042,950	$71,011,870	$88,133,586	$98,624,439	$104,180,645
(13)	Effective State Tax Rate		8.000%	8.000%	8.000%	8.000%	8.000%
(14)	Deferred State Tax Reserve	Line (12) x Line (13)	$3,603,436	$5,680,950	$7,050,687	$7,889,955	$8,334,452
(14a)	Less: State NOL	FY18 NOL true-up plus 75% of FY19 NOL per tax return	$0	$0	$0	$0	$0
(14b)	Net Deferred State Tax Reserve	Line (14) plus Line (14a)	$3,603,436	$5,680,950	$7,050,687	$7,889,955	$8,334,452
(15)	Cumulative Federal Book / Tax Timer	Line (7) - Line (11)	$45,042,950	$71,011,870	$88,133,586	$98,624,439	$104,180,645
(16)	Effective Tax Rate		21.000%	21.000%	21.000%	21.000%	21.000%
(17)	Deferred Federal Tax Reserve	Line (15) x Line (16)	$9,459,020	$14,912,493	$18,508,053	$20,711,132	$21,877,935
(18)	Less: Federal deduction for Deferred State Taxes	If Line (14b) > $0, Line (14b) * -21%, otherwise $0	($756,722)	($1,193,000)	($1,480,644)	($1,656,891)	($1,750,235)
(19)	Less: Federal NOL	FY18 NOL true-up plus 75% of FY19 NOL per tax return	-	$0	$0	$0	$0
(20)	Net Deferred Federal Tax Reserve	Sum of Line (17) through Line (19)	$8,702,298	$13,719,494	$17,027,409	$19,054,241	$20,127,700
(21)	Total Deferred Tax Reserve	Line (14b) + Line (20)	$12,305,734	$19,400,444	$24,078,096	$26,944,196	$28,462,152
	Rate Base Calculation:						
(22)	Gross Plant Additions	Line (3)	$300,589,000	$281,371,000	$261,631,000	$241,370,000	$221,581,000
(23)	Accumulated Book Depreciation	- Line (11)	($15,029,450)	($43,166,550)	($69,329,650)	($93,466,650)	($115,624,750)
(24)	Deferred Tax Reserve	- Line (21)	($12,305,734)	($19,400,444)	($24,078,096)	($26,944,196)	($28,462,152)
(25)	Cumulative Cost of Removal	- Line (4)	$30,013,500	$30,013,500	$30,013,500	$30,013,500	$30,013,500
(26)	Year End Rate Base	Sum of Lines (22) through (25)	$303,267,316	$248,817,507	$198,236,754	$150,972,654	$107,507,598
	Revenue Requirement Calculation:						
(27)	Average Rate Base	Year 1: Line (26) ÷ 2; Year 2 and beyond: (PY Line (26) + CY Line (26)) ÷ 2	$151,633,658	$276,042,411	$223,527,130	$174,604,704	$129,240,126
(28)	Pre-Tax ROR	Page 5	9.49%	9.49%	9.49%	9.49%	9.49%
(29)	Return and Taxes	Line (27) x Line (28)	$14,390,034	$26,196,425	$21,212,725	$16,569,986	$12,264,888
(30)	Book Depreciation	Line (10)	$15,029,450	$28,137,100	$26,163,100	$24,137,000	$22,158,100
(31)	Property Tax expense	Year 1: $0, Year 2: (PY Line (3) - PY Line (11)) x Prop Tax Rate ÷ 2, Year 3 and beyond: (PY Line (3) - PY Line (11)) x Prop Tax Rate 1/	$0	$3,383,881	$6,100,912	$5,480,847	$4,908,800
(32)	Annual Revenue Requirement	Sum of Lines (29) through (31)	$29,419,484	$57,717,406	$53,476,737	$46,187,833	$39,331,788

1/ Property Tax Rate Calculation

'ear Plant in Service	$4,554,343,860	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 6, Page 1
Rate Year Accumulated Depreciation	($1,783,103,879)	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 6, Page 1
Rate Year Net Plant in Service	$2,771,239,981	
Rate Year Property Tax Expense	$65,650,673	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 7, Page 1
Property Tax Rate	2.37%	

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Calculation of Tax Depreciation and Repairs Deduction - 10 Years

	Year			1 (a)	2 (b)	3 (c)	4 (d)	5 (e)
	Federal Tax Depreciation							
	Capital Repairs Deduction							
(1)	Plant Additions	Page 2, Line (3)		$300,589,000				
(2)	Capital Repairs Deduction Rate	Tax Dept	1/	0.00%				
(3)	Capital Repairs Deduction	Line (1) x Line (2)		$0				
	Bonus Depreciation							
(4)	Plant Additions	Line (1)		$300,589,000				
(5)	Less Capital Repairs Deduction	Line (3)		$0				
(6)	Plant Additions Net of Capital Repairs Deduction	Line (4) - Line (5)		$300,589,000				
	Remaining Tax Depreciation							
(7)	Plant Additions	Line (1)		$300,589,000				
(8)	Less Capital Repairs Deduction	Line (3)		$0				
(9)	Less Bonus Depreciation	Line (6)		$0				
(10)	Less Plant Additions Subject to 39 Yr Straight Line Depreciation	Per Tax Dept	1/	$0				
(11)	Remaining Plant Additions Subject to 10 YR MACRS Tax Depreciation	Line (7) - (8) - (9) - (10)		$300,589,000	$300,589,000	$300,589,000	$300,589,000	$300,589,000
(12)	10 YR MACRS Tax Depreciation Rates	IRS Publication 946, Table A-1		10.00%	18.00%	14.40%	11.52%	9.22%
(13)	Total Tax Depreciation on 10 YR MACRS assets	Line (11) x Line (12)		$30,058,900	$54,106,020	$43,284,816	$34,627,853	$27,714,306
(14)	Plant Additions Subject to 39 Yr Straight Line Depreciation	Line (10)		$0	$0	$0	$0	$0
(15)	39 YR SL Depreciation Rates	IRS Publication 946		2.5641%	2.5641%	2.5641%	2.5641%	2.5641%
(16)	Total Tax Depreciation on 39 YR SL assets	Line (14) * Line (15)		$0	$0	$0	$0	$0
(17)	Total Tax Depreciation and Repairs Deduction	Sum of Lines (3), (13), (16)		$30,058,900	$54,106,020	$43,284,816	$34,627,853	$27,714,306
(18)	Includable Cost of Removal	Page 2, Line (4)		$30,013,500	$0	$0	$0	$0
(19)	Total Federal Tax Depreciation, Repairs Deduction and Cost of Removal	Line (17) through (18)		$60,072,400	$54,106,020	$43,284,816	$34,627,853	$27,714,306
	State Tax Deduction							
(20)	Plant Additions	Line (1)		$300,589,000				
(21)	Capital Repairs Deduction Rate	Line (2)		0.00%				
(22)	Capital Repairs Deduction	Line (20) x Line (21)		$0				
	Remaining Tax Depreciation							
(23)	Plant Additions	Line (20)		$300,589,000				
(24)	Less Capital Repairs Deduction	Line (22)		$0				
(25)	Less Plant Additions Subject to 39 Yr Straight Line Depreciation	Per Tax Dept	1/	$0				
(26)	Remaining Plant Additions Subject to 10 YR MACRS Tax Depreciation	Line (23) - Line (24) - Line (25)		$300,589,000	$300,589,000	$300,589,000	$300,589,000	$300,589,000
(27)	10 YR MACRS Tax Depreciation Rates	IRS Publication 946, Table A-1		10.0000%	18.0000%	14.4000%	11.5200%	9.2200%
(28)	Total Tax Depreciation on 10 YR MACRS assets	Line (26) x Line (27)		$30,058,900	$54,106,020	$43,284,816	$34,627,853	$27,714,306
(29)	Plant Additions Subject to 39 Yr Straight Line Depreciation	Line (25)		$0	$0	$0	$0	$0
(30)	39 YR SL Depreciation Rates	IRS Publication 946		2.5641%	2.5641%	2.5641%	2.5641%	2.5641%
(31)	Total Tax Depreciation on 39 YR SL assets	Line (29) * Line (30)		$0	$0	$0	$0	$0
(32)	Total Tax Depreciation and Repairs Deduction	Line (22) + Line (28) + Line (31)		$30,058,900	$54,106,020	$43,284,816	$34,627,853	$27,714,306
(33)	Includable Cost of Removal	Page 2, Line (4)		$30,013,500	$0	$0	$0	$0
(34)	Total State Tax Depreciation, Repairs Deduction and Cost of Removal	Line (32) + Line (33)		$60,072,400	$54,106,020	$43,284,816	$34,627,853	$27,714,306

1/ Per FY 2019 Tax return

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
MACRS Table

MACRS DEPRECIATION BY CLASS OF PROPERTY

Year	3-year	5-year	7-year	10-year	15-year	20-year
1	33.33%	20.00%	14.29%	10.00%	5.00%	3.75%
2	44.45	32	24.49	18%	9.5	7.219
3	14.81	19.2	17.49	14.40%	8.55	6.677
4	7.41	11.52	12.49	11.52%	7.7	6.177
5		11.52	8.93*	9.22%	6.93	5.713
6		5.76	8.92	7.37%	6.23	5.285
7			8.93	6.55%	5.9	4.888
8			4.46	6.55%	5.9	4.522
9				6.56%	5.91	4.462
10				6.55%	5.9	4.461
11				3.28%	5.9	4.462
12					5.9	4.461
13					5.91	4.462
14					5.9	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Cost of Capital

	Description	Capital Structure (a)	Cost Rate (b)	Weighted Return (c) = (a) x (b)	Taxes (d)	Pre-tax Return (e) = (c) + (d)
1	Long Term Debt	46.43%	5.22% [1/]	2.42%		2.42%
2						
3	Preferred Stock	0.08%	4.44% [1/]	0.00%		0.00%
4						
5	Total Common Equity	53.49%	9.60% [3/]	5.14%	1.93% [2/]	7.07%
6						
7	Total Capitalization	100.00%		7.56%	1.93%	9.49%

1/ Company's Effective Cost of Long Term Debt and Preferred Stock
2/ Line 5(c) /(1-0.2732) - Line 5(c)
3/ Per Docket No. 18-150 final order Page 497

Effective Tax Rate	**From Jan 1, 2018**
Federal Tax Rate	21.00%
State Tax Rate	8.00%
Federal Deduction for State Income Taxes	1.68%
State Tax, net of Federal Deduction	6.32%
Federal Tax Rate	21.00%
Effective Tax rate	27.32%

Massachusetts Electric Company
Distribution DG Capital
Summary Illustrative Revenue Requirement - 20 years

			Year 1	Year 2	Year 3	Year 4	Year 5
			(a)	(b)	(c)	(d)	(e)
1	Cumulative Net Historic Capital Adjustment						
2	Annual Revenue Requirement on Year 1 CapEx	Page 2, Line (32)	$22,407,457	$45,648,574	$44,474,730	$39,885,384	$35,447,946
3							
4	Cumulative Net CapEx Adjustment		$22,407,457	$45,648,574	$44,474,730	$39,885,384	$35,447,946
5							
6	O&M		$19,099,500	$0	$0	$0	$0
7							
8	Total		$41,506,957	$45,648,574	$44,474,730	$39,885,384	$35,447,946

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Illustrative Revenue Requirement - 20 Years

	Year		1 (a)	2 (b)	3 (c)	4 (d)	5 (e)
	Depreciable Plant Additions						
(1)	Gross Distribution Plant Additions		$ 496,587,000	$0	$0	$0	$0
(2)	CIP/CIAC		$ (195,998,000)	$ (19,218,000)	$ (19,740,000)	$ (20,261,000)	$ (19,789,000)
(3)	Accum. Gross Distribution Plant Additions	PY Line (3) + CY Line (1) & (2)	$ 300,589,000	$281,371,000	$261,631,000	$241,370,000	$221,581,000
(4)	Cumulative Cost of Removal		$30,013,500	$30,013,500	$30,013,500	$30,013,500	$30,013,500
	Deferred Tax Calculation:						
(5)	Composite Book Depreciation Rate	Assumes 20 year	5.00%	5.00%	5.00%	5.00%	5.00%
	Vintage Year Tax Depreciation:						
(6)	Federal Tax Depreciation	Page 3, Line (31)	$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(7)	Cumulative Federal Tax Depreciation	PY Line (7) + CY Line (6)	$41,285,588	$62,985,108	$83,055,436	$101,622,819	$118,795,469
(8)	State Tax Depreciation	Page 3, Line (46)	$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(9)	Cumulative State Tax Depreciation	PY Line (9) + CY Line (8)	$41,285,588	$62,985,108	$83,055,436	$101,622,819	$118,795,469
(10)	Book Depreciation	Year 1: Line (3) x Line (5) x 50%; Year 2 and beyond: Line (3) x Line (5)	$7,514,725	$14,068,550	$13,081,550	$12,068,500	$11,079,050
(11)	Cumulative Book Depreciation	PY Line (11) + CY Line (10)	$7,514,725	$21,583,275	$34,664,825	$46,733,325	$57,812,375
(12)	Cumulative State Book / Tax Timer	Line (9) - Line (11)	$33,770,863	$41,401,833	$48,390,611	$54,889,494	$60,983,094
(13)	Effective State Tax Rate		8.000%	8.000%	8.000%	8.000%	8.000%
(14)	Deferred State Tax Reserve	Line (12) x Line (13)	$2,701,669	$3,312,147	$3,871,249	$4,391,160	$4,878,648
(14a)	Less: State NOL	FY18 NOL true-up plus 75% of FY19 NOL per tax return	$0	$0	$0	$0	$0
(14b)	Net Deferred State Tax Reserve	Line (14) plus Line (14a)	$2,701,669	$3,312,147	$3,871,249	$4,391,160	$4,878,648
(15)	Cumulative Federal Book / Tax Timer	Line (7) - Line (11)	$33,770,863	$41,401,833	$48,390,611	$54,889,494	$60,983,094
(16)	Effective Tax Rate		21.000%	21.000%	21.000%	21.000%	21.000%
(17)	Deferred Federal Tax Reserve	Line (15) x Line (16)	$7,091,881	$8,694,385	$10,162,028	$11,526,794	$12,806,450
(18)	Less: Federal deduction for Deferred State Taxes	If Line (14b) > $0, Line (14b) * -21%, otherwise $0	($567,350)	($695,551)	($812,962)	($922,144)	($1,024,516)
(19)	Less: Federal NOL	FY18 NOL true-up plus 75% of FY19 NOL per tax return	-	$0	$0	$0	$0
(20)	Net Deferred Federal Tax Reserve	Sum of Line (17) through Line (19)	$6,524,531	$7,998,834	$9,349,066	$10,604,650	$11,781,934
(21)	Total Deferred Tax Reserve	Line (14b) + Line (20)	$9,226,200	$11,310,981	$13,220,315	$14,995,810	$16,660,582
	Rate Base Calculation:						
(22)	Gross Plant Additions	Line (3)	$300,589,000	$281,371,000	$261,631,000	$241,370,000	$221,581,000
(23)	Accumulated Book Depreciation	- Line (11)	($7,514,725)	($21,583,275)	($34,664,825)	($46,733,325)	($57,812,375)
(24)	Deferred Tax Reserve	- Line (21)	($9,226,200)	($11,310,981)	($13,220,315)	($14,995,810)	($16,660,582)
(25)	Cumulative Cost of Removal	- Line (4)	$30,013,500	$30,013,500	$30,013,500	$30,013,500	$30,013,500
(25)	Year End Rate Base	Sum of Lines (22) through (25)	$313,861,575	$278,490,244	$243,759,360	$209,654,365	$177,121,543
	Revenue Requirement Calculation:						
(26)	Average Rate Base	Year 1: Line (26) ÷ 2; Year 2 and beyond: (PY Line (26) + CY Line (26)) ÷ 2	$156,930,788	$296,175,910	$261,124,802	$226,706,862	$193,387,954
(27)	Pre-Tax ROR	Page 5	9.49%	9.49%	9.49%	9.49%	9.49%
(28)	Return and Taxes	Line (27) x Line (28)	$14,892,732	$28,107,094	$24,780,744	$21,514,481	$18,352,517
(29)	Book Depreciation	Line (10)	$7,514,725	$14,068,550	$13,081,550	$12,068,500	$11,079,050
(30)	Property Tax expense	Year 1: $0, Year 2: (PY Line (3) - PY Line (11)) x Prop Tax Rate ÷ 2, Year 3 and beyond: (PY Line (3) - PY Line (11)) x Prop Tax Rate 1/	$0	$3,472,930	$6,612,436	$6,302,403	$6,016,379
(31)	Annual Revenue Requirement	Sum of Lines (29) through (31)	$22,407,457	$45,648,574	$44,474,730	$39,885,384	$35,447,946

1/ Property Tax Rate Calculation

Rate Year Plant in Service	$4,554,343,860	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 6, Page 1
Rate Year Accumulated Depreciation	($1,783,103,879)	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 6, Page 1
Rate Year Net Plant in Service	$2,771,239,981	
Rate Year Property Tax Expense	$65,650,673	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 7, Page 1
Property Tax Rate	2.37%	

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Calculation of Tax Depreciation and Repairs Deduction - 20 Years

	Year			1 (a)	2 (b)	3 (c)	4 (d)	5 (e)
	Federal Tax Depreciation							
	Capital Repairs Deduction							
(1)	Plant Additions	Page 2, Line (3)		$300,589,000				
(2)	Capital Repairs Deduction Rate	Tax Dept	1/	0.00%				
(3)	Capital Repairs Deduction	Line (1) x Line (2)		$0				
	Bonus Depreciation							
(4)	Plant Additions	Line (1)		$300,589,000				
(5)	Less Capital Repairs Deduction	Line (3)		$0				
(6)	Plant Additions Net of Capital Repairs Deduction	Line (4) - Line (5)		$300,589,000				
	Remaining Tax Depreciation							
(7)	Plant Additions	Line (1)		$300,589,000				
(8)	Less Capital Repairs Deduction	Line (3)		$0				
(9)	Less Bonus Depreciation	Line (6)		$0				
(10)	Less Plant Additions Subject to 39 Yr Straight Line Depreciation	Per Tax Dept	1/	$0				
(11)	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line (7) - (8) - (9) - (10)		$300,589,000	$300,589,000	$300,589,000	$300,589,000	$300,589,000
(12)	20 YR MACRS Tax Depreciation Rates	IRS Publication 946, Table A-1		3.7500%	7.2190%	6.6770%	6.1770%	5.7130%
(13)	Total Tax Depreciation on 20 YR MACRS assets	Line (11) x Line (12)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(14)	Plant Additions Subject to 39 Yr Straight Line Depreciation	Line (10)		$0	$0	$0	$0	$0
(15)	39 YR SL Depreciation Rates	IRS Publication 946		2.5641%	2.5641%	2.5641%	2.5641%	2.5641%
(16)	Total Tax Depreciation on 39 YR SL assets	Line (14) * Line (15)		$0	$0	$0	$0	$0
(17)	Total Tax Depreciation and Repairs Deduction	Sum of Lines (3), (13), (16)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(18)	Includable Cost of Removal	Page 2, Line (4)		$30,013,500	$0	$0	$0	$0
(19)	Total Federal Tax Depreciation, Repairs Deduction and Cost of Removal	Line (17) through (18)		$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650
	State Tax Deduction							
(20)	Plant Additions	Line (1)		$300,589,000				
(21)	Capital Repairs Deduction Rate	Line (2)		0.00%				
(22)	Capital Repairs Deduction	Line (20) x Line (21)		$0				
	Remaining Tax Depreciation							
(23)	Plant Additions	Line (20)		$300,589,000				
(24)	Less Capital Repairs Deduction	Line (22)		$0				
(25)	Less Plant Additions Subject to 39 Yr Straight Line Depreciation	Per Tax Dept	1/	$0				
(26)	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line (23) - Line (24) - Line (25)		$300,589,000	$300,589,000	$300,589,000	$300,589,000	$300,589,000
(27)	20 YR MACRS Tax Depreciation Rates	IRS Publication 946, Table A-1		3.7500%	7.2190%	6.6770%	6.1770%	5.7130%
(28)	Total Tax Depreciation on 20 YR MACRS assets	Line (26) x Line (27)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(29)	Plant Additions Subject to 39 Yr Straight Line Depreciation	Line (25)		$0	$0	$0	$0	$0
(30)	39 YR SL Depreciation Rates	IRS Publication 946		2.5641%	2.5641%	2.5641%	2.5641%	2.5641%
(31)	Total Tax Depreciation on 39 YR SL assets	Line (29) * Line (30)		$0	$0	$0	$0	$0
(32)	Total Tax Depreciation and Repairs Deduction	Line (22) + Line (28) + Line (31)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(33)	Includable Cost of Removal	Page 2, Line (4)		$30,013,500	$0	$0	$0	$0
(34)	Total State Tax Depreciation, Repairs Deduction and Cost of Removal	Line (32) + Line (33)		$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650

1/ Per FY 2019 Tax return

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
MACRS Table

MACRS DEPRECIATION BY CLASS OF PROPERTY

Year	3-year	5-year	7-year	10-year	15-year	20-year
1	33.33%	20.00%	14.29%	10.00%	5.00%	3.75%
2	44.45	32	24.49	18	9.5	7.219
3	14.81	19.2	17.49	14.4	8.55	6.677
4	7.41	11.52	12.49	11.52	7.7	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.9	4.888
8			4.46	6.55	5.9	4.522
9				6.56	5.91	4.462
10				6.55	5.9	4.461
11				3.28	5.9	4.462
12					5.9	4.461
13					5.91	4.462
14					5.9	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Cost of Capital

	Description	Capital Structure (a)	Cost Rate (b)	Weighted Return (c) = (a) x (b)	Taxes (d)	Pre-tax Return (e) = (c) + (d
1	Long Term Debt	46.43%	5.22% 1/	2.42%		2.42%
2						
3	Preferred Stock	0.08%	4.44% 1/	0.00%		0.00%
4						
5	Total Common Equity	53.49%	9.60% 3/	5.14%	1.93% 2/	7.07%
6						
7	Total Capitalization	100.00%		7.56%	1.93%	9.49%

1/ Company's Effective Cost of Long Term Debt and Preferred Stock
2/ Line 5(c) /(1-0.2732) - Line 5(c)
3/ Per Docket No. 18-150 final order Page 497

Effective Tax Rate	**From Jan 1, 2018**
Federal Tax Rate	21.00%
State Tax Rate	8.00%
Federal Deduction for State Income Taxes	1.68%
State Tax, net of Federal Deduction	6.32%
Federal Tax Rate	21.00%
Effective Tax rate	27.32%

Massachusetts Electric Company
Distribution DG Capital
Summary Illustrative Revenue Requirement - 30 years

			Year 1	Year 2	Year 3	Year 4	Year 5
			(a)	(b)	(c)	(d)	(e)
1	Cumulative Net Historic Capital Adjustment						
2	Annual Revenue Requirement on Year 1 CapEx	Page 2, Line (32)	$19,988,935	$41,323,237	$40,931,324	$37,072,120	$33,325,934
3							
4	Cumulative Net CapEx Adjustment		$19,988,935	$41,323,237	$40,931,324	$37,072,120	$33,325,934
5							
6	O&M		$19,099,500	$0	$0	$0	$0
7							
8	Total		$39,088,435	$41,323,237	$40,931,324	$37,072,120	$33,325,934

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Illustrative Revenue Requirement - 30 Years

	Year		1 (a)	2 (b)	3 (c)	4 (d)	5 (e)
	Depreciable Plant Additions						
(1)	Gross Distribution Plant Additions		$ 496,587,000	$0	$0	$0	$0
(2)	CIP/CIAC		$ (195,998,000)	$ (19,218,000)	$ (19,740,000)	$ (20,261,000)	$ (19,789,000)
(3)	Accum. Gross Distribution Plant Additions	PY Line (3) + CY Line (1) & (2)	$300,589,000	$281,371,000	$261,631,000	$241,370,000	$221,581,000
(4)	Cumulative Cost of Removal		$30,013,500	$30,013,500	$30,013,500	$30,013,500	$30,013,500
	Deferred Tax Calculation:						
(5)	Composite Book Depreciation Rate	Assumes 30 year	3.33%	3.33%	3.33%	3.33%	3.33%
	Vintage Year Tax Depreciation:						
(6)	Federal Tax Depreciation	Page 3, Line (31)	$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(7)	Cumulative Federal Tax Depreciation	PY Line (7) + CY Line (6)	$41,285,588	$62,985,108	$83,055,436	$101,622,819	$118,795,469
(8)	State Tax Depreciation	Page 3, Line (46)	$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(9)	Cumulative State Tax Depreciation	PY Line (9) + CY Line (8)	$41,285,588	$62,985,108	$83,055,436	$101,622,819	$118,795,469
(10)	Book Depreciation	Year 1: Line (3) x Line (5) x 50%; Year 2 and beyond: Line (3) x Line (5)	$5,009,817	$9,379,033	$8,721,033	$8,045,667	$7,386,033
(11)	Cumulative Book Depreciation	PY Line (11) + CY Line (10)	$5,009,817	$14,388,850	$23,109,883	$31,155,550	$38,541,583
(12)	Cumulative State Book / Tax Timer	Line (9) - Line (11)	$36,275,771	$48,596,258	$59,945,553	$70,467,269	$80,253,886
(13)	Effective State Tax Rate		8.000%	8.000%	8.000%	8.000%	8.000%
(14)	Deferred State Tax Reserve	Line (12) x Line (13)	$2,902,062	$3,887,701	$4,795,644	$5,637,382	$6,420,311
(14a)	Less: State NOL	FY18 NOL true-up plus 75% of FY19 NOL per tax return	$0	$0	$0	$0	$0
(14b)	Net Deferred State Tax Reserve	Line (14) plus Line (14a)	$2,902,062	$3,887,701	$4,795,644	$5,637,382	$6,420,311
(15)	Cumulative Federal Book / Tax Timer	Line (7) - Line (11)	$36,275,771	$48,596,258	$59,945,553	$70,467,269	$80,253,886
(16)	Effective Tax Rate		21.000%	21.000%	21.000%	21.000%	21.000%
(17)	Deferred Federal Tax Reserve	Line (15) x Line (16)	$7,617,912	$10,205,214	$12,588,566	$14,798,126	$16,853,316
(18)	Less: Federal deduction for Deferred State Taxes	If Line (14b) > $0, Line (14b) * -21%, otherwise $0	($609,433)	($816,417)	($1,007,085)	($1,183,850)	($1,348,265)
(19)	Less: Federal NOL	FY18 NOL true-up plus 75% of FY19 NOL per tax return	-	$0	$0	$0	$0
(20)	Net Deferred Federal Tax Reserve	Sum of Line (17) through Line (19)	$7,008,479	$9,388,797	$11,581,481	$13,614,276	$15,505,051
(21)	Total Deferred Tax Reserve	Line (14b) + Line (20)	$9,910,541	$13,276,498	$16,377,125	$19,251,658	$21,925,362
	Rate Base Calculation:						
(22)	Gross Plant Additions	Line (3)	$300,589,000	$281,371,000	$261,631,000	$241,370,000	$221,581,000
(23)	Accumulated Book Depreciation	- Line (11)	($5,009,817)	($14,388,850)	($23,109,883)	($31,155,550)	($38,541,583)
(24)	Deferred Tax Reserve	- Line (21)	($9,910,541)	($13,276,498)	($16,377,125)	($19,251,658)	($21,925,362)
(25)	Cumulative Cost of Removal	- Line (4)	$30,013,500	$30,013,500	$30,013,500	$30,013,500	$30,013,500
(25)	Year End Rate Base	Sum of Lines (22) through (25)	$315,682,142	$283,719,152	$252,157,492	$220,976,292	$191,127,555
	Revenue Requirement Calculation:						
(26)	Average Rate Base	Year 1: Line (26) ÷ 2; Year 2 and beyond: (PY Line (26) + CY Line (26)) ÷ 2	$157,841,071	$299,700,647	$267,938,322	$236,566,892	$206,051,924
(27)	Pre-Tax ROR	Page 5	9.49%	9.49%	9.49%	9.49%	9.49%
(28)	Return and Taxes	Line (27) x Line (28)	$14,979,118	$28,441,591	$25,427,347	$22,450,198	$19,554,328
(29)	Book Depreciation	Line (10)	$5,009,817	$9,379,033	$8,721,033	$8,045,667	$7,386,033
(30)	Property Tax expense	Year 1: $0, Year 2: (PY Line (3) - PY Line (11)) x Prop Tax Rate ÷ 2, Year 3 and beyond: (PY Line (3) - PY Line (11)) x Prop Tax Rate 1/	$0	$3,502,613	$6,782,944	$6,576,255	$6,385,573
(31)	Annual Revenue Requirement	Sum of Lines (29) through (31)	$19,988,935	$41,323,237	$40,931,324	$37,072,120	$33,325,934

1/ Property Tax Rate Calculation

Year Plant in Service	$4,554,343,860	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 6, Page 1
Rate Year Accumulated Depreciation	($1,783,103,879)	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 6, Page 1
Rate Year Net Plant in Service	$2,771,239,981	
Rate Year Property Tax Expense	$65,650,673	DPU 18-150, Exhibit NG-RRP-2 (C), Schedule 7, Page 1
Property Tax Rate	2.37%	

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Calculation of Tax Depreciation and Repairs Deduction -30 Years

	Year			1 (a)	2 (b)	3 (c)	4 (d)	5 (e)
	Federal Tax Depreciation							
	Capital Repairs Deduction							
(1)	Plant Additions	Page 2, Line (3)		$300,589,000				
(2)	Capital Repairs Deduction Rate	Tax Dept	1/	0.00%				
(3)	Capital Repairs Deduction	Line (1) x Line (2)		$0				
	Bonus Depreciation							
(4)	Plant Additions	Line (1)		$300,589,000				
(5)	Less Capital Repairs Deduction	Line (3)		$0				
(6)	Plant Additions Net of Capital Repairs Deduction	Line (4) - Line (5)		$300,589,000				
	Remaining Tax Depreciation							
(7)	Plant Additions	Line (1)		$300,589,000				
(8)	Less Capital Repairs Deduction	Line (3)		$0				
(9)	Less Bonus Depreciation	Line (6)		$0				
(10)	Less Plant Additions Subject to 39 Yr Straight Line Depreciation	Per Tax Dept	1/	$0				
(11)	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line (7) - (8) - (9) - (10)		$300,589,000	$300,589,000	$300,589,000	$300,589,000	$300,589,000
(12)	20 YR MACRS Tax Depreciation Rates	IRS Publication 946, Table A-1		3.7500%	7.2190%	6.6770%	6.1770%	5.7130%
(13)	Total Tax Depreciation on 20 YR MACRS assets	Line (11) x Line (12)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(14)	Plant Additions Subject to 39 Yr Straight Line Depreciation	Line (10)		$0	$0	$0	$0	$0
(15)	39 YR SL Depreciation Rates	IRS Publication 946		2.5641%	2.5641%	2.5641%	2.5641%	2.5641%
(16)	Total Tax Depreciation on 39 YR SL assets	Line (14) * Line (15)		$0	$0	$0	$0	$0
(17)	Total Tax Depreciation and Repairs Deduction	Sum of Lines (3), (13), (16)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(18)	Includable Cost of Removal	Page 2, Line (4)		$30,013,500	$0	$0	$0	$0
(19)	Total Federal Tax Depreciation, Repairs Deduction and Cost of Removal	Line (17) through (18)		$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650
	State Tax Deduction							
(20)	Plant Additions	Line (1)		$300,589,000				
(21)	Capital Repairs Deduction Rate	Line (2)		0.00%				
(22)	Capital Repairs Deduction	Line (20) x Line (21)		$0				
	Remaining Tax Depreciation							
(23)	Plant Additions	Line (20)		$300,589,000				
(24)	Less Capital Repairs Deduction	Line (22)		$0				
(25)	Less Plant Additions Subject to 39 Yr Straight Line Depreciation	Per Tax Dept	1/	$0				
(26)	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line (23) - Line (24) - Line (25)		$300,589,000	$300,589,000	$300,589,000	$300,589,000	$300,589,000
(27)	20 YR MACRS Tax Depreciation Rates	IRS Publication 946, Table A-1		3.7500%	7.2190%	6.6770%	6.1770%	5.7130%
(28)	Total Tax Depreciation on 20 YR MACRS assets	Line (26) x Line (27)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(29)	Plant Additions Subject to 39 Yr Straight Line Depreciation	Line (25)		$0	$0	$0	$0	$0
(30)	39 YR SL Depreciation Rates	IRS Publication 946		2.5641%	2.5641%	2.5641%	2.5641%	2.5641%
(31)	Total Tax Depreciation on 39 YR SL assets	Line (29) * Line (30)		$0	$0	$0	$0	$0
(32)	Total Tax Depreciation and Repairs Deduction	Line (22) + Line (28) + Line (31)		$11,272,088	$21,699,520	$20,070,328	$18,567,383	$17,172,650
(33)	Includable Cost of Removal	Page 2, Line (4)		$30,013,500	$0	$0	$0	$0
(34)	Total State Tax Depreciation, Repairs Deduction and Cost of Removal	Line (32) + Line (33)		$41,285,588	$21,699,520	$20,070,328	$18,567,383	$17,172,650

1/ Per FY 2019 Tax return

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
MACRS Table

MACRS DEPRECIATION BY CLASS OF PROPERTY

Year	3-year	5-year	7-year	10-year	15-year	20-year
1	33.33%	20.00%	14.29%	10.00%	5.00%	3.75%
2	44.45	32	24.49	18	9.5	7.219
3	14.81	19.2	17.49	14.4	8.55	6.677
4	7.41	11.52	12.49	11.52	7.7	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.9	4.888
8			4.46	6.55	5.9	4.522
9				6.56	5.91	4.462
10				6.55	5.9	4.461
11				3.28	5.9	4.462
12					5.9	4.461
13					5.91	4.462
14					5.9	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Massachusetts Electric Company
DG Capital Investment Recovery Illustration
Cost of Capital

	Description	Capital Structure (a)	Cost Rate (b)	Weighted Return (c) = (a) x (b)	Taxes (d)	Pre-tax Return (e) = (c) + (d)
1	Long Term Debt	46.43%	5.22% 1/	2.42%		2.42%
2						
3	Preferred Stock	0.08%	4.44% 1/	0.00%		0.00%
4						
5	Total Common Equity	53.49%	9.60% 3/	5.14%	1.93% 2/	7.07%
6						
7	Total Capitalization	100.00%		7.56%	1.93%	9.49%

1/ Company's Effective Cost of Long Term Debt and Preferred Stock
2/ Line 5(c) /(1-0.2732) - Line 5(c)
3/ Per Docket No. 18-150 final order Page 497

Effective Tax Rate	**From Jan 1, 2018**
Federal Tax Rate	21.00%
State Tax Rate	8.00%
Federal Deduction for State Income Taxes	1.68%
State Tax, net of Federal Deduction	6.32%
Federal Tax Rate	21.00%
Effective Tax rate	27.32%

Information Request EDC-3

Request:

Based on historical data, estimate the threshold $/kW at or below which interconnecting customers have agreed to pay to interconnect. Provide data by group, where possible.

Response:

Based on historical data, National Grid estimates that $400/kW is the threshold at or below which interconnecting customers have agreed to pay to interconnect; however, as discussed in more detail below, $/kW is only one indicator of DG project viability and interconnecting customers will pay more than $400/kW depending on the value they place on other factors.

Please refer to D.P.U. 20-75 National Grid Comments on Straw Proposal, Attachment 1, showing the System Modification costs customers have paid over the past 10 years, with the customer data grouped by DG process track, i.e., over 25kW (Expedited and Standard process track) and less than or equal to 25 kW (as a proxy for Simplified process track). The historical data in Attachment 1 is the basis of the estimates below.

The table below shows the average $/kW for applications submitted in recent years, grouped by applications that made their System Modification payment, applications that have withdrawn and applications that are yet to decide. The average acceptable range of $/kW to interconnect in recent years appears to be $133/kW to $226/kW, as shown in the first column in the table below.

Table 1- Average $/kW that customers have paid for System Modifications in recent years grouped by application status

Year Application Submitted	Applications that Moved Forward (Average $/kW)	Applications that Canceled (Average $/kW)	Applications that Are Yet to Make a Decision (Average $/kW)
2017	$189	$601	$1,431
2018	$226	$392	$1,048
2019	$145	$371	$335
2020	$133	NA	$238

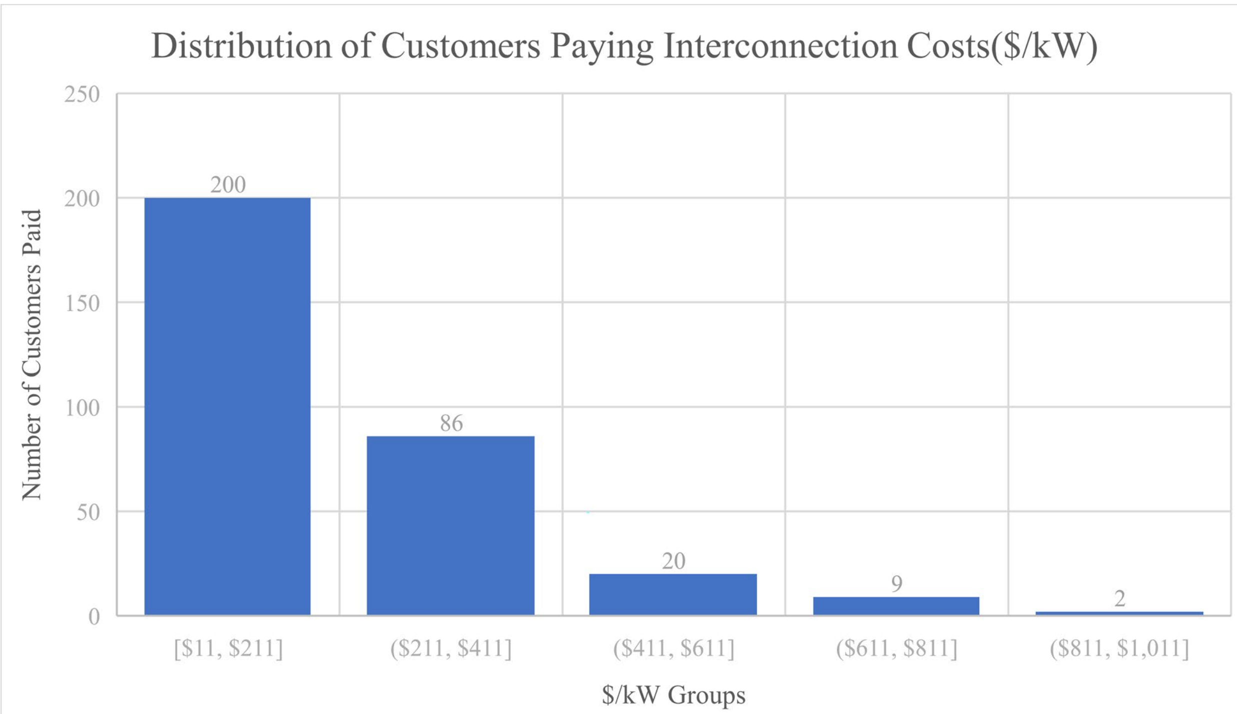
Overall Average	$194	$486	$870

Even if the average $/kW is between $133/kW and $226/kW, the customers have made payments over $400/kW for System Modifications, as shown in the table below, and the viability of a DG project depends not only on interconnection cost but also on other factors, such as installation cost, land cost, permitting cost, incentives, etc.

Table 2- Maximum $/kW that customers have made paid for System Modifications in recent years grouped by size category

Year ISA Executed	Between 25kW & 450kW	Between 451kW & 2MW	Over 2MW
2017	$202	$564	$414
2018	$953	$687	$752
2019	$1,009	$366	$829
2020	$358	$429	$359

The histogram below shows a high number of customers paying interconnection costs up to $400/kW. Based on the histogram distribution and the historical data referenced above, National Grid estimates $400/kW for System Modifications to be the threshold at or below which interconnecting customers have agreed to pay to interconnect in recent years, subject to the caveat that $/kW is only one factor customers consider in evaluating the viability of a DG project.


Distribution of Customers Paying Interconnection Costs($/kW)
Number of Customers Paid
250
200
150
100
50
0
200
86
20
9
2
[$11, $211]
($211, $411]
($411, $611]
($611, $811]
($811, $1,011]
$/kW Groups

Information Request EDC-4

Request:

If the Department seeks to implement a provisional system planning program based on the study results of the above referenced group(s), how quickly following the completion of associated impact studies could the company prepare and submit a proposal to the Department?

Response:

The Company could prepare and submit a provisional system planning program proposal to the Department based on the results of the distribution system and transmission system impact studies associated with the Group Studies referenced in the Company's response to Information Request EDC-1 approximately three to four months after completion of all of the Group Studies and the associated impact studies.[1]

The provisional system planning program proposal National Grid would develop during this three to four month period would be analogous to the last step in the long-term planning process National Grid described in its D.P.U. 20-75 Reply Comments at 8, i.e., the box labeled CIP-Pre-Approval Process. During this period National Grid would determine the criteria for proposing CIPs (Capital Investment Projects) and for proposing CIP Fees. Stakeholder engagement would occur as part of the Group Study process.

National Grid proposes that development of the provisional system planning process occur before Group Study participants are presented with Interconnection Service Agreements ("ISAs") so that any proposed CIP Fees the Department approves can be included in the applicable ISAs. To implement this, the Company may need to put the applicable projects on hold during the provisional planning process through Department approval (or disallowance) of the Company's proposed CIPs and CIP Fees before issuing ISAs. This approach would require Department approval as it would exceed current Group Study timeframes to issue an executable ISA.[2]

[1] For the purposes of this response, "completion" would be after all of the participants in a Group Study have satisfied their post-study documentation requirements that the Company typically requires before issuing an executable ISA, including any required design documentation changes based on the protection requirements identified in the study results (and Company approval of all such changes).

[2] Section 3.4.1(i) of the Standards for Interconnection of Distributed Generation, D.P.U. 19-55 and D.P.U. 20-63 EDC Compliance Tariff (Revised 11.12.20).

Information Request EDC-5

Request:

Are there any federal law implications that should be considered concerning sharing costs of EPS upgrades with interconnecting customers over an extended period of time and in particular after the EPS upgrade has been constructed?

Response:

National Grid believes there could be federal law implications concerning the sharing of costs of EPS upgrades with interconnecting customers over an extended period of time after those upgrades have been constructed. National Grid envisions that such implications could arise if certain DG interconnection customers in the queue ultimately utilize the constructed EPS upgrades to engage in wholesale sales of electricity (as opposed to participating solely in retail-level programs), or subsequent interconnections are made to the EPS upgrades by resources that engage in wholesale transactions. It seems likely that FERC would consider such EPS upgrades to be subject to its jurisdiction with respect to transmission service used to facilitate wholesale energy purchases, or sales to third-parties, as well as certain interconnections to those facilities for DG intending to engage in wholesale sales.[1] This could limit the Department's ability to implement a sharing of costs of such EPS upgrades with all interconnecting DG customers, because DG customers that interconnect pursuant to ISO-NE's tariff might not be subject to Massachusetts-jurisdictional retail tariffs and charges through which EPS upgrade costs would be allocated and recovered.

Also, while National Grid understands that the purpose of the proposal is to identify distribution system infrastructure investments needed to facilitate the interconnection of DG, the proliferation of these resources is also causing, and will likely continue to cause, the need for upgrades to higher-voltage FERC-jurisdictional transmission facilities. The allocation of costs for such

[1] Under FERC's "first use" policy, if a facility becomes subject to wholesale open access under a FERC-approved tariff (e.g., ISO-New England's OATT), and a subsequent interconnection will result in connecting a generator to that facility that would be used to facilitate a wholesale sale, the interconnection is subject to FERC jurisdiction. With respect to Qualifying Facilities ("QFs"), when such facilities intend to sell all of their output to their interconnected electric utility under PURPA, their interconnections are state-jurisdictional. However, when the electric utility interconnecting with a QF does not purchase all of the QF's output and instead transmits the QF's power in interstate commerce, FERC exercises jurisdiction over that interconnection. In Order No. 2222, FERC declined to exercise jurisdiction over the interconnections of distributed energy resources ("DER") participating in wholesale markets exclusively as part of a DER aggregation, and FERC clarified in Order No. 2222-A that this limitation applied to QFs as well.

transmission facilities would be subject to FERC jurisdiction. As such, any sharing mechanism adopted by the Department for how the costs of such transmission facilities are passed through and recovered from retail customers or DG customers would only apply to those costs allocated under FERC rules to Massachusetts entities (e.g., Massachusetts distribution utilities). Finally, any higher-voltage FERC-jurisdictional transmission facilities required to be constructed to effectuate this proposal would be subject to the open access requirements of FERC Order 888 and the ISO-NE Tariff, and therefore, the capacity of such transmission facilities could not be reserved solely for the benefit of DG customers within the MA state interconnection queue, but instead would need to be made available to any generator seeking interconnection, including generators within the ISO-NE interconnection queue. This could result in DG customers, or all distribution customers depending on how costs are allocated as between DG customers and all distribution customers, paying for any higher-voltage FERC-jurisdictional transmission facilities required to be constructed to effectuate this proposal but not being able to utilize some or all of the constructed capacity of such transmission facilities. To enable such a reservation of capacity, similar to what the DPU is considering for distribution level upgrades, modifications to the OATT will need to be developed and adopted by ISO-NE and approved by the FERC.

Prepared by or under the supervision of: Ian Springsteel